MEETING FUTURE ENERGY NEEDS

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENTS

REPORT 666A SP

ontario hydro

System Planning Division

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DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT A

LOAD FORECASTING METHODOLOGY

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1.0 LONG-TERM FORECASTING[1]

In the long run, electricity demand depends on a large number of factors and a complex set of interrelationships between them. The forecaster must decide which of these factors and interrelations are the most important and focus on them. Models are used to enable such a focus. A model represents those parts of the real world which the modeller chooses as important to the task at hand, while ignoring the rest. Successful modelling requires appropriate choice of which relationships are important. In the forecasting of electricity demand, several choices are possible.

Some forecasters use a mental model, based on their own experience, to generate a forecast. Such a forecast, like any forecast, depends on and reflects its assumptions.

In forecasting so specific a quantity as electricity demand in Ontario over as long a term as 20 years, formal models are virtually a necessity. Use of a model forces precise identification and specification of the assumptions. Different models can focus on different dimensions of electricity use. The models can then be used to examine the effects of changes in the assumptions. In addition a formal model can be arranged to produce a large amount of detail regarding components of electricity demand and these components can be examined and reconciled with known uses in the present, and with forecasts made by others. Formal models are therefore used as the practical input into the long-term load forecast, with the interpretation of results tempered by the judgment and experience of the forecaster.

A frequently used approach to forecasting is to note that, over a long period, the relationship between overall economic activity and electricity demand has remained relatively stable, influenced by only a few variables in addition to aggregate economic activity. A simple relationship can be estimated using mathematical statistics showing electricity demand as a function of economic activity, price of electricity relative to competing fuels and relative to the general level of all prices, demographic variables, etc. This is called a single-equation econometric model.

Another way of forecasting electricity demand is to recognize that fundamental historical relationships are much more complex than can effectively be modelled by a single relationship between a few variables. This requires at least a long-term demographic-macroeconomic model linked with sectoral models for distinct sectors of the economy (residential, commercial and industrial). These models are driven by demographics and detailed knowledge about the present structure and trends of macroeconomic relationships within sectors and industries. The outputs of such a complex model consist both of total energy demand in the future and the market shares of electricity and other fuels. This approach is called multi-equation econometric modelling.

Finally, total electricity demand can also be derived by adding up the demand created by each and every end-use of electricity. A forecast taking this approach uses engineering-oriented models which derive energy demand from a "bottom up" approach. These models study energy consumption at the detailed and disaggregate level of end uses such as space heating, lighting and cooking. In its simplest form, then, an end-use model is a basic accounting model which adds up the demand created by each end-use of electricity (equipment stock x electricity utilization rate). The forecaster's critical task in implementing an end-use model is to make assumptions and projections of detailed activity levels for all electricity utilization technologies.

The usefulness of end-use models can best be understood in terms of the historical events which led to their development. Prior to the oil embargo of 1973, even simplistic approaches could be used to capture the steady growth in demand trends. However, the detailed nature of subsequent conservation programs required assessments of demand for specific end uses of energy. Traditional energy demand models are much too aggregate to reflect the impacts of programs that in some cases are specific to end-use by fuel, subsector, and geographical area. The traditional models, based on behavioural relationships estimated using historical data, are not able to analyze the structural change that many demand options (strategic conservation, load management, cogeneration) aim to achieve. Demand forecasts based on end-use methodology are not only capable of providing the needed level of disaggregation, but can also incorporate the dynamics of changing energy demand.

Proponents of econometric modelling claim that a basic weakness of the simple end-use approach is the inability to capture behavioural relationships such as the dependence of electricity consumption on income level or GNP. Another drawback is the large number of forecasts or assumptions that are required about each end use. The latest trend in energy forecasting, therefore, is to blend the econometric and the end-use approaches.

For example, in EPRI's (Electrical Power Research Institute) residential sector model REEPS (Residential End-Use Energy Planning System) fuel shares for heating are determined econometrically. This adds the benefit of behavioural response and elements of causality to what are otherwise "behaviour free" models. Market penetration and usage projections are based on econometric relations that are drawn from the theory of consumer choice. These relations are sensitive to energy costs, technological performance characteristics of alternative appliances, and household survey data. Parallel models for the commercial and industrial sectors respectively are COMMEND and INDEPTH. INDEPTH is not yet fully developed.

Ontario Hydro maintains separate end-use and econometric models. The Ontario Hydro end-use model was originally obtained from the Ministry of Energy. Since that time, both the Ministry and Ontario Hydro have restructured and updated their models independently. The multiple-equation econometric model is the EDEM model, developed and maintained by the Load Forecasts Department.

Both REEPS and and COMMEND models have been purchased from EPRI and, when the needed data are collected, will be included in the portfolio of models used for the production of the Load Forecast.

The use of several models allows the forecaster to take into account more of the available information about the past in order to assess the future. All the models have some historical data in common and some that are not common, and each also requires assumptions about a different set of explanatory variables. The forecaster can therefore discover whether the forecasts of electricity demand will differ significantly using the different methodologies. Any differences between the forecasts are instructive, since they can be traced directly to the model or to the underlying assumptions. This gives the forecaster the ability to ensure consistency.

Similar considerations apply to short-term forecasting. However, in the short term, the variability of weather affects electricity demand more than the set of variables relating to the level of economic activity, fuel prices, or demographics. Demand in the short term is also heavily determined by the existing stock of energy-using capital equipment, which tends to change only very slowly. Therefore it is more useful to view demand in the short term as primarily related to demand in the recent past, and then to apply a knowledge of external changes and judgment to round out the energy demand picture.

2.0 TREATMENT OF UNCERTAINTY

The imprecision inherent in any forecasting process and the uncertainty of events the forecasters are trying to predict unavoidably produce a forecast which is uncertain to a greater or lesser degree. While the available forecasting techniques can all be used to produce a "most likely" forecast (ie, a forecast using what is considered to be the most realistic set of parameters given present expectations of the future), the recognition that other directions are possible means that a range or band of possible outcomes rather than a single estimate should be provided. Ontario Hydro uses two methods to quantify the uncertainty associated with the long-term Load Forecast.

i) Scenario Method

This is by far the easiest and most common method used (2, 3).

Alternative scenarios are postulated, each characterized by a different set of assumptions for the explanatory variables. The forecasting model used to produce the most likely forecast is then used to simulate forecasts for each alternative scenario.

The scenario method usually involves the use of high, low and median estimates of explanatory variables to obtain a high, low and most-likely forecast. Depending on the forecasting method used, the high scenario would consider higher economic growth, higher saturation and usage of applicances, larger population and lower energy price assumptions than the most-likely scenario. The low scenario would have similarly low values for the above variables.

The scenario method also provides an effective tool for policy analysis by measuring the effect of a proposed policy or government measure. Policies of interest might be a government decision to ban future coal-burning plants in an attempt to control acid rain, subsidies to specific fuel users, or decreased reliance on oil imports.

There are, however, a few shortcomings with the scenario method. When producing an alternative scenario, it is imperative that a reasonable relationship between explanatory variables be maintained. Judgment must be exercised to ensure that the variables used to build a scenario form a consistent set. For example, if higher GNP growth is postulated, one would expect lower, not higher unemployment rates (unless, of course, there is higher population growth due to immigration etc). There is also a difficulty in quantifying a probability range between scenarios since the scenarios describe mutually exclusive events. However, it has been the experience at Ontario Hydro that the upper and lower scenarios resemble the 60% confidence interval obtained through the error modelling statistical technique discussed below.

ii) Error Modelling

The error modelling method, which was developed by Ontario Hydro, looks at the forecast errors made in the past as a way of dealing with future uncertainty.

Forecast error may be caused by many factors. Some of these factors are: error in forecast of energy prices, economic growth, government policy, and the rate and penetration of technological improvements. In addition to these unforeseen shifts in exogenous variables, errors also reflect differing methodologies used in preparing the forecast. The forecast error is thus a convenient summary index of uncertainty in the forecast.

The first step in using this approach is to calculate the percentage error for each year forecasted in the past. For a forecast produced in year "t", the error for the first year forecasted (t+1) is termed the first year forecast error, the error for the second year forecasted (t+2) is termed the second year forecast error ... By looking at a number of historical forecasts, a probability distribution can be obtained for the first year forecast error, the second year forecast error etc. Each distribution is characterized by a mean and a variance. The next step is to model these variances against time. The model results are then used to determine uncertainty limits for each year forecasted. This can be displayed as confidence limits for different levels of probability. This is done in Chapter 4, Figure 4.7, which shows the 60% confidence interval.

3.0 REFERENCES

(1) ONTARIO HYDRO, Economics and Forecasts Division, Load Forecast Report No. 851209, March 1986.

(2) WACK, P., "Scenarios: Unchartered Waters Ahead". Harvard Business Review, September/October 1985.

(3) WACK, P., "Scenarios: Shooting the Rapids". Harvard Business Review, November/December 1985.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT B

THE OPTIONS

December 1987

System Planning Division

3449G

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1.0 INTRODUCTION

This report is intended to supplement Chapter 8 of the Draft Demand/Supply Planning Strategy. It is based on Report 651SP which documents the information available at the end of Phase I of the Demand/Supply Options Study. More detailed information on Phase I is included in Report 652SP. Phase II activities developed alternative plans based on this information. This report also reflects additional information which has become available since the completion of Phase I.

The report follows the structure of Chapter 8, discussing demand options, alternative technologies, traditional supply options and purchases from neighbouring provinces. Finally, an overall comparison is made of costs and the potential contribution each could make in the year 2000. The relative impacts on the Provincial economy are also presented.

This report uses 'standard' costs as a measure of the costs of different options as applied to the Ontario Hydro system. This evaluation of standard costs is explained in Appendix A. All standard costs are quoted in 1985 price levels, based on projections of real price levels in the year 2000. These projections were prepared in 1985 before the drop in oil prices in 1986. Current expectations are that by the year 2000, oil prices will once again rise to a level where oil is considerably more expensive than coal as a source of heat. Comments in this report referring to oil as an expensive fuel will likely still apply.

2.0 DEMAND OPTIONS

Demand options are of three kinds; all three are designed to assist customers in getting the best value from their power system. Strategic growth programs encourage customers to use more electricity for efficient purposes. Load shifting options are designed to distribute demand throughout a time period in such a way that the power system is used more effectively. Efficiency improvement includes those options that aim to decrease the demand for electricity by reducing waste and improving how electricity is used. Because conservation is often taken to mean "doing with less", in this report, we have called it "efficiency improvements" to indicate that the level of service is not reduced.

Strategic growth options are not considered here because they will not help us meet our expected capacity shortfall. However, our load forecast does account for the natural growth in demand for electricity associated with increased sales of electrical services which customers will undertake on their own. The load forecast also includes some strategic growth due to sales for efficient electrical uses, which we promote through advertising, information newsletters, and other marketing programs.

Natural conservation is undertaken by customers without any incentive offered by Ontario Hydro. Customers will conserve in this way because they are interested in the prospect of smaller electricity bills. A provision for these natural conservation measures is included in our load forecast, just as an allowance is made for the natural growth in demand.

Additional improvements in efficiency or shifts in the timing of demands can be implemented through the participation of Ontario Hydro and the municipal utilities. Customers need incentives, such as low interest loans or rebates, to make these improvements. The estimated potential for load shifting and efficiency improvements is shown in Figure 2.1.

Some of you may feel that growth and demand reduction options are contradictory: selling and conserving may seem incompatible. In fact, they are complementary. The principle that guides both activities is the same. Ontario Hydro, by mandate, is committed to assisting customers in getting the best value from their electricity system. Encouraging some customers to improve their efficiency of electrical use will assist them in obtaining a desired energy service using less energy at a lower cost. At the same time, encouraging customers to adopt electrical services can increase productivity, improve standards of living and displace energy produced from non-renewable and imported fossil fuels.

Figure 2.1

Standard Costs For Demand Options

	Peak Load Reduction By Year 2000 (MW)	Average Energy (Av MW)	Standard Cost ($/MW.h)
LOAD SHIFTING	1000	-	30-40
EFFICIENCY IMPROVEMENTS (Utility Sponsored)			
- Residential Sector	500-2000	170-680	25-45
- Commercial Sector	300-1300	230-980	25-45
- Industrial Sector	200-700	150-530	25-45
TOTAL	1000-4000	550-2200	25-45

Both of the activities to assist customers should be considered as part of resource conservation. Ontario Hydro is committed to resource conservation by promoting the efficient use of electricity and by encouraging the substitution of electricity for coal, oil and gas where the use of these fuels is not economic.

2.1 Load Shifting

More generating capacity is necessary to supply load at peak periods than at non-peak periods. As electricity cannot be stored in large quantities, we must have enough generating capacity to meet the peak demand on the coldest, darkest and busiest days and nights of winter. During non-peak periods, some of our capacity lies unused, waiting for the next peak. However, if our demand was uniform throughout the day, the week, and the year, then we would only need enough generating capacity to meet average energy demand. In this case, some of our existing generation capacity would become surplus. This spare capacity could then be used to supply an increase in load and no new generation facilities would have to be built. The more effective use of existing generation can lead to a reduction in the cost of electricity. The ideal aim of load shifting is to move closer to this uniform demand and the resulting reduction in electricity costs.

A uniform demand throughout the year is not really a serious prospect, because of the timing of customers demands and the characteristics of the generating system. However, by reducing the demand during peak periods, we can increase loads in general without building new supply facilities.

The challenge to utilities planning load shifting is to successfully develop programs which provide adequate incentives for customers to change their patterns of consumption of electricity. To do this, strategies must be devised to avoid customer inconvenience. For example, a storage water heater can heat water during non-peak periods (11:00 pm to 7:00 am) for use during peak periods (7:00 am to 11:00 pm). But the heater must be large enough to store sufficient hot water for a family's total daily needs. If the heater cannot meet their hot water needs, they will not likely continue to participate in the utility's load shifting program.

There are two main ways to shift demand from peak periods to non-peak periods. A utility can directly control demand with devices that shut off electrical appliances. A directly controlled water heater heats water during the night and shuts off during the day. For several decades many municipalities have been controlling water heaters for short periods. Demand can also be controlled with indirect methods. In this scheme, lower rates during off-peak periods give customers the incentive to shift their use of electricity away from peak demand periods when rates are higher.

The potential impact of either direct or indirect controls is difficult to predict. We cannot be sure how many customers will purchase appliances with direct control devices; nor can we be certain that rate incentives will change the consumption habits of customers, or change them for very long.

Industrial and commercial customers are unlikely to accept direct utility load control. With large investments dependent on electricity and adequate resources to determine the best use of energy, these sectors usually prefer to make their own electricity consumption decisions. We expect residential customers to participate if the right conditions exist. Ontario Hydro must offer incentives to customers in the form of lower rates for direct-controlled appliances or financial assistance for the purchase of these appliances. Most customers will not agree to direct controls if they perceive that their standard of living will be diminished or that their participation will entail sacrifices. Customers expect to receive heat and other energy services when they want them.

The success of indirect controls depends on how willing customers are to change their electricity consumption habits. Ontario Hydro cannot be sure that customers will choose to shift their consumption to off-peak periods; they may prefer to pay more for electricity and consume at their own convenience.

Ontario Hydro has conducted separate field studies on both direct and indirect controls. Even after extensive study, proposed changes are not always accepted. In the early 1980s, after several years of study including 2 years of public hearings, we proposed time-of-use rates, an indirect method of control, and received approval from the Ontario Energy Board to have higher electricity rates in the winter than in the summer. However, this proposal was rejected by the Ontario Government because time-of-use rates initially discriminate against some customers. Under time-of-use rates, rates more accurately reflect the cost to Ontario Hydro of generating electricity. The utility will collect the same amount of money, but customers who consume during non-peak periods will have lower electricity bills, and those who consume during the peaks will have higher electricity bills. In the short term, some customers win and some lose. For example, if a time-of-use rate scheme gives customers the incentive to shift from winter to summer consumption, then in the short term, summer lodge operators will win and ski club operators will lose.

In the long run, more customers can shift their consumption to non-peak periods because greater changes are possible. A substantial shift of consumption will distribute demand more evenly over the peak period and the non-peak period. The net result will be a reduction in total system energy cost because the existing generating capacity is being used more effectively. At this point, the number of winners will exceed the number of losers. Because of the potential long-term benefits, time-of-use rates are being accepted in an increasing number of jurisdictions.

What is the potential for load shifting in Ontario? Given the difficulties of estimating the effectiveness of either direct or indirect control, we forecast that 1600 to 3100 megawatts of peak load could theoretically be shifted by the year 2000. However, it appears undesirable for Ontario Hydro to shift more than 1000 to 1500 megawatts of peak load by the end of the

century. As illustrated by Figure 2.2, if we shifted more than 1000 megawatts, then our reliability problems in the off-peak period would become just as significant as they are during our peak period. Once the load is distributed evenly, throughout the 24 hour day, there is no more potential for load shifting.

A shift of 1000 megawatts of peak load for example, is a substantial reduction of our peak power generating requirements. This is an amount equivalent to about one-third of the generating capacity of a large coal or nuclear station, or about enough to serve the peak power needs of the City of Hamilton.

To assess the standard costs of load shifting options, we need to understand that although load shifting can contribute 1000 to 1500 megawatts of peak power, it will contribute nothing to our average energy needs. Load shifting simply moves electricity demand to another time; it does not reduce the demand for electricity. Let's examine how costs are incurred by meeting an increase of load with load shifting.

Curve A on Figure 2.3 shows our load curve for a peak day before an increase of load is added to the system. Curve B shows the new load curve as a result of the new load. Note that the shape of the new curve is exactly the same as the original. The shape of the curves reflects the normal pattern of customer electricity use on a peak day. With the addition of the new load increment (Curve B), our generation system is now unreliable since the system capability is exceeded. Note that Curve B shows a high peak period of electricity use. If we implement the load shifting option, our load curve flattens somewhat and produces Curve C. Under Curve C, the peak is lessened. However, the area under Curves B and C is exactly the same; in other words, although load shifting has reduced the peak demand of the new load, the average energy demands of the loads are the same after load shifting has been implemented. How, then, do we meet the energy demands of the new load?

The energy demands of the new increment of load must be supplied by the existing base system: hydraulic, nuclear, coal and oil generation. Consequently, the main component of the standard cost of a load shifting option is fuel costs. Our base system must run harder now, to meet the energy requirements of the increment: we will need to supply more fuel to our coal, nuclear and oil plants. These fuel costs are calculated into the standard cost of the load shifting option. There are other costs as well, associated with the implementation of the direct or indirect controls. Standard costs for the load shifting option range between a low of $30/MW.h and a high of $40/MW.h. If the base system were characterized by a lot of high operating cost plant, standard costs for the load shifting option rise to a range of $40/MW.h to $52/MW.h. Under this base system, more of the additional energy required to supplement the load shifting option is supplied by oil-fired generation.

Figure 2.2
LOAD SHIFTING POTENTIAL IN ONTARIO

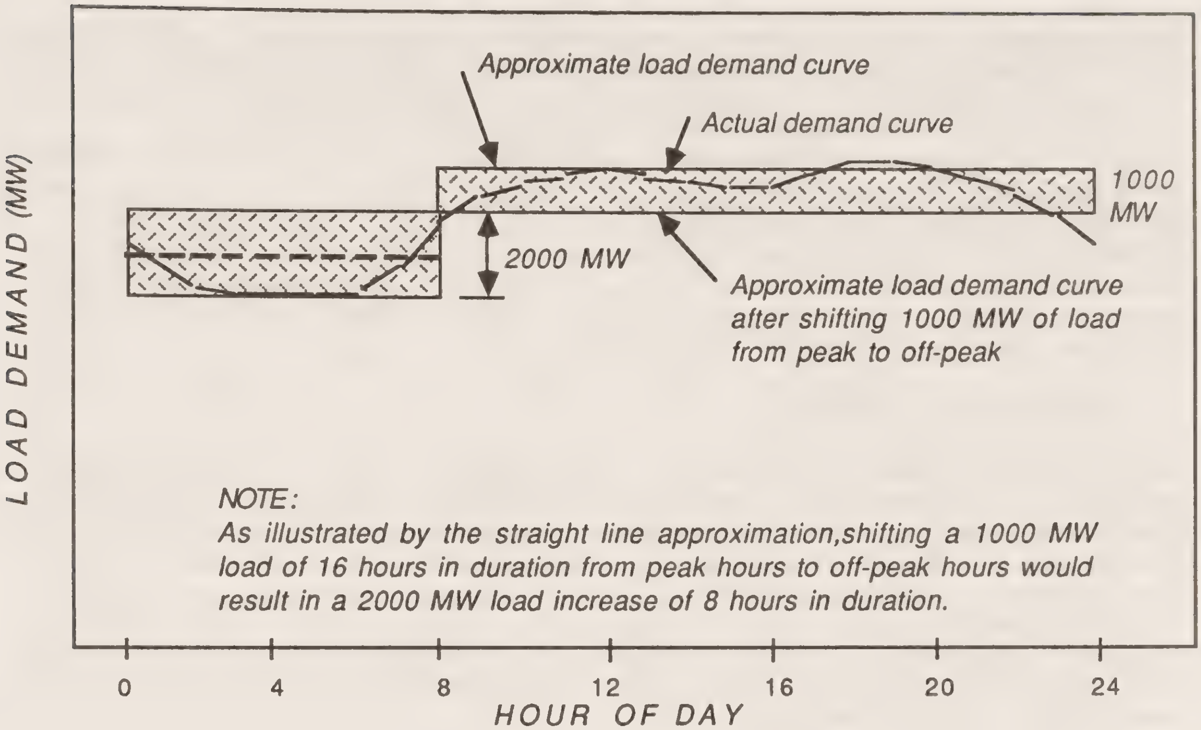
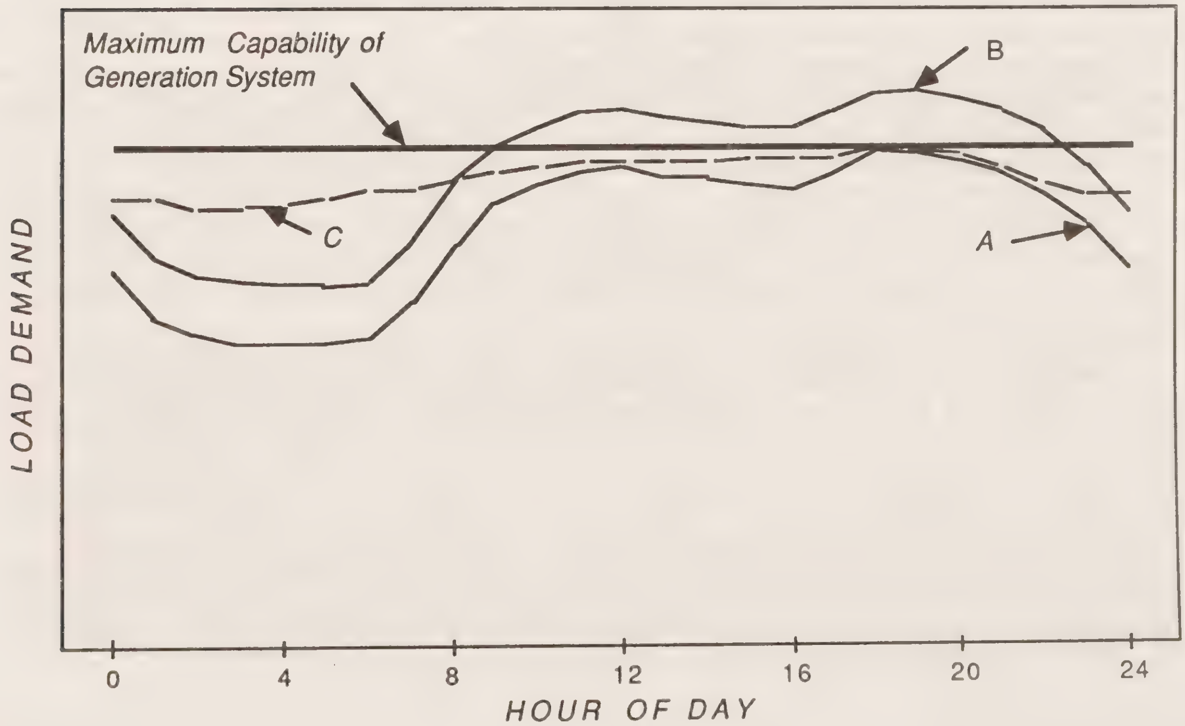


Figure 2.3
ILLUSTRATION OF BENEFITS OF LOAD SHIFTING



We are continuing with further field studies of the potential for direct and indirect load shifting. Participation from all types of customers -- industrial, commercial, residential and agricultural -- will be necessary if load shifting is to succeed. First year results from a five year time-of-use study are encouraging: seventy percent of participants report that they like the opportunity to save money on their bills by taking the trouble to manage their electricity use more wisely. Forecasting how customers will react to load shifting incentives is difficult for utility planners; it is much easier to forecast how much a generating station will produce. However, we are encouraged by our early study results and will continue with further study in this area.

2.2 Improving Efficiency

Efficiency improvements have a very wide range of costs. Some are so cheap and easy to implement that customers will exploit them without any incentive from Ontario Hydro. These natural conservation steps -- it could be something as simple as turning off a light switch -- are included in our load forecasts. Other measures, although not quite as cheap, are still economic over the life of the equipment, while still others are quite obviously uneconomic. Suppose that you are considering purchasing a small hand drill with a more efficient motor. How would you determine if this conservation step is worthwhile?

You would first determine the energy saving and the increase in initial capital cost. The hand drill uses about 250 watts and sells for about $30. The high efficiency motor might reduce the drill's consumption of electricity to 150 watts. With the new high efficiency motor, the drill now sells for $40. You know that you only use a drill about 10 hours a year. Your saving is calculated in the following way: 100 watts saved for 10 hours equals a saving of 1000 watt hours or 1 kilowatt hour per year. At an electricity cost of 5¢ per kilowatt hour, 5¢ a year is saved with the new high efficiency drill. Yet the new drills cost $10 more than the inefficient drills. Therefore, the initial $10 investment yields a 0.5 percent per annum return. If you take the time to do this calculation, you will obviously not proceed with this conservation step. In this case, it is better from society's perspective to use more energy rather than to spend resources such as copper and steel to make the motor more efficient.

A more rewarding investment in improved energy efficiency might involve the purchase of a home freezer. Consider for example, one which typically costs $500, runs 2500 hours per year and uses 400 watts. It can be expected to have a life of over 20 years. For an extra $100, it might be possible to purchase a better model which only uses 300 watts (better insulation, more efficient motor) and also runs 2500 hours per year. The saving in energy would be 100 watts for 2500 hours/year or 250 kW.h/year. At 5¢ per unit this represents a saving of $12.50/year. Based on the $100 higher purchase price, this yields a return of 12.5% per annum. In this case, it would appear to be wiser for the consumer to purchase the more expensive model. It would certainly be better from society's perspective.

The efficiency improvements we have considered here are more expensive than natural conservation and should be less expensive than building and operating new electricity supply facilities; they will certainly be less expensive than the hand drill example.

If the desire is to defer or possibly eliminate the need for new supply facilities, two fundamental methods exist to achieve this purpose; either improving the efficiency level of electricity use to perform the same energy service, or discouraging the use of electricity in some circumstances. Ontario Hydro does not discourage the use of electricity where it performs a valued service, for several reasons. First, it is not consistent with our mandate to meet the electricity needs of the people of Ontario. Second, it should only be considered where other energy forms, such as oil or gas, are preferable. And third, discouraging the use of electricity does not help Ontario solve its energy problems. It simply transfers the problem of expanding energy supplies to someone else. We believe that there are more responsible and effective ways to meet the province's energy needs.

Improving the efficiency of electricity use is accomplished by reducing waste and loss of electricity and by introducing more effective equipment. Waste is reduced by ensuring that only the electricity necessary to complete a desired task is used, and that it is otherwise shut off. Electricity losses can be controlled by thermally sealing houses and water heaters. Equipment such as heat pumps and high efficiency lighting provide the same energy service with less electricity. Now, let's examine our estimates of what can be done to improve the efficiency of electricity use in the residential, commercial and industrial sectors of Ontario.

Residential

In the residential sector, further opportunities exist for the improved sealing and insulating of single family detached houses and for the introduction of efficient appliances and equipment, such as heat pumps. Standard costs for these options range from $25/MW.h to $45/MW.h. The expenses that comprise these costs include the cost of insulation, new equipment, better quality houses, interest on loans, and so on. Significant savings could be achieved in new houses if construction methods met R2000 standards. In addition, much remains to be done to retrofit insulation in existing homes. We are reasonably confident that as much as 500 megawatts of peak load could be conserved in the residential sector by the year 2000; the savings could be as high as 2000 MW. The corresponding reduction in energy demand would be 170-680 average megawatts.

Commercial

Assessing the potential for improving efficiency in the commercial sector is more difficult because of the diversity of electricity uses. We have identified ten commercial segments, each with its own pattern of energy use. These segments include the familiar commercial operations -- retail

sales, offices, -- and also some less obvious sources of conservation potential -- educational institutions, multi-residential buildings (apartment complexes), churches and cultural institutions, hotels and motels, recreation establishments, and a variety of transportation services. To help us study this sector, we enlisted the services of a firm of independent consultants with considerable expertise in the area of energy management. They have provided us with an extensive list of options available to customers for improving efficiency with a clearly documented analysis of the cost and benefits of each option.

Customers will recover their investment in energy efficiency over varying lengths of time, depending on the option. Generally, the longer the pay-back period, the less likely will the customer be to undertake that efficiency improvement option. We assume that any option which pays back in three years or less is sufficiently attractive for commercial customers to undertake on their own initiative. These options are considered natural conservation; Ontario Hydro need not offer incentives to customers to undertake these steps. For options with a pay-back period of three years or more, we could offer a variety of incentives to commercial customers. The standard costs for these efficiency improvement options range between $25/MW.h and $45/MW.h. Our earlier studies (Phase I) suggested that we could be confident that 300 megawatts of peak load and 230 megawatts of energy could be conserved in the commercial sector by the year 2000. With greater incentives, the savings could be as high as 1300 MW of peak load and 980 average megawatts of energy. We have been continuing investigations and now feel that although the upper level hasn't changed very much, the lower end of the range could be somewhat higher.

Industrial

The greatest variety of electricity use occurs in the industrial sector. Electricity is used to fire boilers, dry materials, heat water or air, melt metals, drive motors, light buildings and a host of other activities and processes. Four main kinds of end use improvements were identified for the industrial sector in Phase I: one, energy efficient lighting; two, energy efficient motors; three, variable speed motors; and four, the substitution of compressed air drive equipment with direct electric drive equipment.

About a quarter of our total electricity demand is for industrial motors. There is some potential for increasing the efficiency of these motors, but it is not as great as might first appear. A simple analysis would show that most motors are on average about 70% efficient and that the cost of increasing a motor's efficiency to 80% is relatively small. At 80% efficiency, the same amount of motor power can be provided with 22% of the total system demand instead of 25%. This would apparently show a potential saving of 3% of total demand just from this one option. However, it is very unlikely that all of this would be an economic step. Closer analysis reveals that 75 percent of the energy used by industrial motors is consumed by a few big motors of 50 horse power or more. These motors are already

over 90 percent efficient. Industries would simply not allow money to be wasted by large inefficient motors. Further improvement can be gained by making some of the vast number of smaller motors more efficient. However, with smaller motors and motors that are used relatively few hours per year, it becomes increasingly difficult to justify the expense of higher efficiency.

The introduction of variable speed motors will have some efficiency improvement effect. These motors are better suited to driving pumps where variable flows are required because they use less electricity to perform their function than traditional constant speed motors. There may be more potential in improving the efficiency of application of motors than there is in increasing the efficiency of the motors themselves.

Based on limited information, we estimated in Phase I that efficiency improvement options for the industrial sector would likely have standard costs similar to the standard costs for the commercial sector: $25/MW.h to $45/MW.h. We were confident that 200 megawatts of peak load and 150 average megawatts of energy consumed by the industrial sector could be conserved by the year 2000. The savings could be as high as 700 megawatts of peak load and 530 average megawatts of energy if greater incentives were offered.

Since then, studies carried out for us by a number of industrial energy management consultants confirm that these estimates of potential are in the correct range.

<u>There are Barriers to Overcome</u>

Improving efficiency, like load shifting, faces potential difficulties or barriers to implementation. Energy efficiency is only one of our customers' goals. When efficiency improvement conflicts with a more highly valued goal, customers will not likely choose to conserve. Keeping lights on all night may be energy inefficient, but it may also add to the security of the home and its occupants. And perhaps what is most important, the occupants may feel more secure with a well-lighted house and yard. There are other inefficient practices that continue because efficiency conflicts with some normal business practices. Electricity used by apartment tenants is recorded on one central meter. Under this system, there is no way to make individual tenants accountable for their use of electricity.

Other barriers to the implementation of efficiency improvement options exist. Customers may not act in their own financial interest because of a lack of information, resistance to change or skepticism concerning potential benefits. Customers would probably not respond voluntarily to a program which financially benefits Ontario Hydro unless it also benefitted them directly. In some cases, there may be legal, institutional, social or regulatory constraints on Ontario Hydro's ability to promote efficiency. Furthermore, many of the efficiency programs assume that customers have access to capital. This may be a reasonable assumption where commercial and industrial customers are concerned; however, it may not be where residential and agricultural customers are concerned.

Some strategies exist to overcome these barriers. The government or Ontario Hydro could provide rebates, grants or low cost loans to customers who otherwise would have no access to capital. Tenants could be given an incentive to conserve through benefit sharing plans. Inadequate information and customer skepticism could be countered with effective information like the Energuide labels that appear on new appliances. The media could also play a further role in informing customers of the benefits of conservation.

Another Look at the Potential for Efficiency Improvements

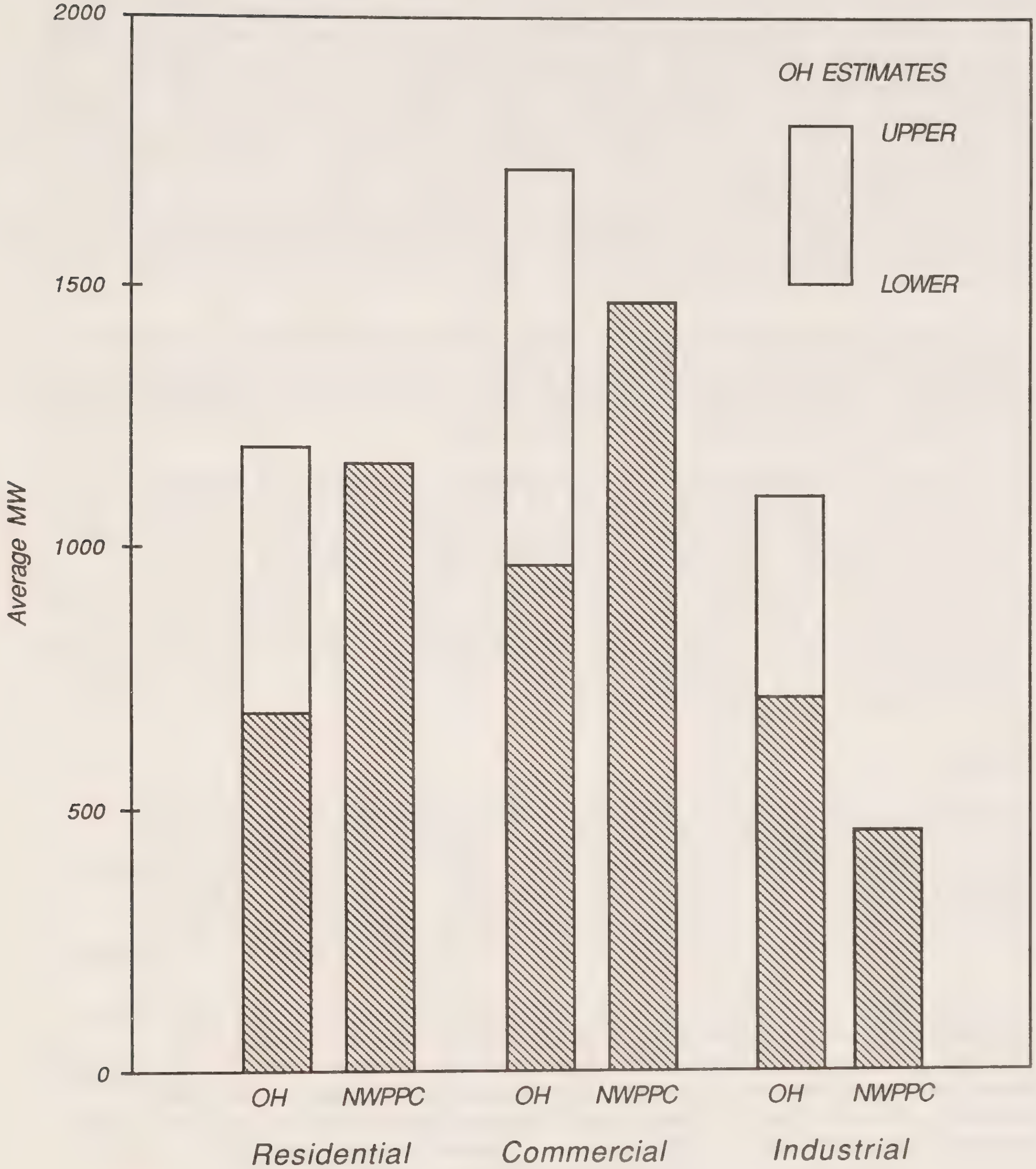
In an effort to substantiate our estimates of the potential for efficiency improvements, we have adapted the methods used in a conservation study by the Northwest Power Planning Council to Ontario. The NWPPC is an interstate agency with members from Idaho, Montana, Oregon and Washington. The council was created to encourage conservation and the development of renewable resources in the northwest United States. Since the climate and the cost of electricity in the NWPPC region are similar to what we experience in Ontario, we thought a comparison of their findings with ours would be useful.

We applied their estimates of improved efficiency for various electricity uses to Ontario. In Figure 2.4, we have compared their estimates to our efficiency improvement estimates including natural conservation. Our estimate of conservation potential for our residential and commercial sectors is reasonably consistent with NWPPC's estimate. However, our estimates for improved efficiency in the industrial sector exceed what the NWPPC expect their industrial users to achieve. The evaluation of the conservation potential of the industrial sector is especially difficult because of the diversity of electricity uses. However, at least for the commercial and residential sectors, the comparison with NWPPC estimates suggests that our initial estimate of conservation potential is in the right ball park.

Further Implementation Issues

In some jurisdictions, the implementation of efficiency improvements may reduce electricity rates. Rates can be reduced if the cost to the utility of supplying an increase in load, with conventional supply options, is greater than the utility's average revenue. This cost-revenue relationship frequently exists in jurisdictions where extra power needs have to be supplied by expensive oil or gas. Suppose that in such a jurisdiction the cost of supplying an increase of load is 7¢ per kilowatt hour and the average revenue is 5¢ per kilowatt hour. If a conservation option were implemented, costs would decrease faster than revenue. Therefore, this utility could offer 2¢ per kilowatt hour as an incentive to conserve without any increase in electricity rates. If the incentive required were less than 2¢, electricity rates would tend to fall.

Figure 2.4
COMPARISON OF CONSERVATION ESTIMATES



NOTES

OH - Ontario Hydro's estimates include natural conservation.
A range is shown to indicate the potential based on varying levels of incentives.

NWPPC - Northwest Power Planning Council's estimates of efficiency improvements applied to Ontario.

This type of cost-revenue relationship exists in many American utilities: it does not exist in Ontario at present. Our incremental costs are not much different from our average revenue, and, in the short run, our costs are lower than our average revenue. If efficiency improvements are implemented here, we cannot be certain that our costs will decrease faster than our revenue. For example, in the short run, extra power is supplied by coal at 2.5¢ per kilowatt hour. Our average revenue at the wholesale level is about 4¢ per kilowatt hour. In this case, conservation incentives offered by Ontario Hydro will involve rate increases. However, the customers who have participated in the conservation program -- the costs of which have resulted in the rate increases -- will on balance benefit from reduced energy use and lower bills despite the rate increases. In other words, customers who do not participate will subsidize customers who do.

It is not clear that efficiency improvements which create such inequities should be implemented. To make this decision, we need to weigh the undesirability of the inequities against the general social desirability of conservation.

Another difficulty associated with implementing conservation concerns the reliability of estimates. The results of implementing a conservation option always differ from the estimated potential. We are not quite certain why this difference occurs. It is possible that once a customer takes a conservation step -- perhaps by insulating an attic or by adding a heat pump -- electricity bills are generally lower and they are less concerned about controlling their use of electricity. They begin to leave lights on or use extra hot water. These possibilities make it difficult for a utility to predict the results of conservation.

2.3 Summary

We believe that approximately 1000 MW of peak load can be shifted to off-peak periods using Time-of-Use Rates or direct load control. In addition, we expect that utility sponsored efficiency improvement programs can reduce the demand for peak power in Ontario in the year 2000 by 1000-4000 megawatts and the demand for energy by 550-2190 average megawatts. Standard costs will fall into the range of $25/MW.h to $45/MW.h.

We recognize that our information on the demand options is not sufficient. Specifically, we lack adequate information about how customers use electricity and how much more efficient they can become. We do not know how customers will respond to the available incentives. What effect will information, audits, loans, grants and standards have on motivating people to conserve? We need more information to answer these questions.

We also do not know to what degree efficiency improvements will actually increase the consumption of electricity. Many energy efficient applications, such as electric heat pumps and micro-wave heating, may displace gas or oil services, and in so doing increase the demand for electricity. Similarly, customers who have implemented conservation have the tendency, as we noted above, to increase their demand for electricity in response to lower electricity bills.

Further study is required before we will have an adequate understanding of the future role of demand options in Ontario. This was recognized early in this study and more detailed studies have been initiated to provide more knowledge in such areas as design, marketing, participation rates, etc., for the promising options.

So the question isn't - "Do demand options have a role?" They clearly do. But, more importantly, Ontario Hydro has to ask itself, "How can we be most effective in helping our customers use electricity more efficiently?" and "How long will it take to develop and deliver successful programs?"

3.0 ALTERNATIVE TECHNOLOGIES

Most of these developing technologies (Figure 3.1) have been available to Ontario Hydro for years. The only new alternatives are fuel cells and photovoltaics. The others -- cogeneration, wood and peat-fuelled generation, wind turbines, and waste-fuelled generation -- have been technically viable for quite some time. However, as they have only been cost competitive in special circumstances, these alternatives have seen little service. In some other jurisdictions, a few of the alternatives have flourished because of conditions which enhance their commercial viability. These include: high priced electricity due to an overdependence on oil and gas, regulations requiring utilities to pay high prices for privately generated power, and the availability of tax credits. We do not foresee a substantial expansion of the alternative options here because these conditions do not exist in Ontario. Yet some of the alternatives could play an effective supplementary role.

An accurate forecast of the contribution the alternates could make is difficult to obtain. However, as supplements they can help in three possible ways. First, Ontario Hydro could develop some of the alternates to meet small increases in demand. Second, in conjunction with industrial users, Ontario Hydro could help develop cogeneration plants in industries which require both heat and electricity. And third, alternatives could be used to meet the electricity needs of communities remote from the power system grid. The cost of electricity in these communities is high because diesel oil is used to fuel electricity generators. Many of the alternatives are cost competitive with diesel-fuelled generators.

3.1 Cogeneration

As a heavily industrialized province, Ontario has a large potential for cogeneration. Cogeneration has traditionally interested large industries which need process steam and produce a waste by-product suitable for fuel. Pulp and paper companies have wood waste; oil refineries have waste gases; and chemical companies also produce combustible wastes suitable for burning. In a cogeneration plant, the fuel is burned to raise high temperature steam to drive a turbine. This process produces two energy products: one, electricity generated from the turbines that can be used by the industry or sold to Ontario Hydro; and two, low pressure, low temperature steam used in the industry's production process.

There are at least four fundamental questions industries will ask themselves before installing cogeneration facilities.

The first question asked is, "What sort of fuel have I to burn?" Here, the industry will want to know if they produce any waste product that has a heat value. If a waste fuel is available, then cogeneration may be worthwhile.

Figure 3.1

Standard Costs For Alternative Technologies

Alternative Technology	Potential By Year 2000 (MW)	Average Capacity Factor (%)	Standard Cost ($/MW.h)
WIND	*	20	86
SOLAR	*	20	71
PEAT	*	5	84
FUEL CELL	*	5	51
MUNICIPAL SOLID WASTE	50 - 300		
- Large		65	31
- Small		60	69
COGENERATION	150 - 1000		
- Gas		70	52
- Waste		70	32
- Wood Waste	*	88	73
- Wood Chips	*	10	89
SMALL HYDRO	20 - 50		
- Redevelopment		70	27
- New		70	61

* Due to their high cost, these technologies are not expected to make significant contributions to the power requirements of Ontario by the year 2001; however, there is potential for wind and solar to displace expensive diesel fuel in remote Northern communities.

The industry will want to be certain this fuel will be available well into the future: a cogeneration plant involves significant capital expenditures, the value of which can only be recovered over long periods of time. Some pulp and paper companies, for example, are considering changing to "thermo-mechanical pulping". This process produces more paper of a higher quality from the same quantity of pulp wood; however, as less waste is produced, there is little combustible fuel for cogeneration. If waste fuel is not available, fuel such as natural gas will have to be purchased and the cogeneration may not be economic.

Alternatively, an industry may already be using a premium fuel such as natural gas to produce process heat which could more efficiently and profitably be used in a cogeneration mode of operation. This would entail an increased fuel consumption but yield electricity for internal use or sale to Ontario Hydro.

A second question an industry will want to ask is, "How much steam or hot water do I need"? The answer to this question determines how big a cogeneration plant will be. The plant size should be appropriate for the steam required.

The next question is, "Do I expect to use steam for a long period of time"? An industry may discover a source of energy more efficient than steam. For example, in industries where steam is used to dry materials, it may be more efficient to use an electrical heat pump dehumidifier.

The final question for an industry considering installing cogeneration is, "How much electricity do I need and what will Ontario Hydro pay for my surplus"? The electricity produced is used to greatest advantage when it reduces the need to buy electricity from Ontario Hydro. However, if there is a surplus, Ontario Hydro will provide further incentive by offering to buy the surplus electricity. The 1987 rate means that an industry can expect \$26-\$36/MW.h for their surplus electricity, depending on the capacity factor.

Ontario presently has about 500 MW of industrial cogeneration. Few plants have been added since the 1970s. There are two main reasons why cogeneration slowed down in Ontario in the early 80s. First, most industries prefer to invest in their main business, not in the business of electricity generation, and second, the low cost of electricity in Ontario makes large-scale development of cogeneration economical only in special cases where the cost of alternatives is more expensive.

Because of the high cost of electricity in the United States, cogeneration has thrived in several American jurisdictions. Many of these utilities rely on oil and gas. An oil or gas-burning cogeneration plant is clearly preferable to large scale conventional plants that burn oil or gas because, at 70-80%, the thermal efficiency of cogeneration is superior to the 38% efficiency of large electrical plants. This is the choice that faces utilities which burn a lot of oil or gas; it is not a choice Ontario

Hydro must face because we do not burn much oil or gas. Our main fuels are coal and uranium. These fuels are more plentiful and until the 1986 drop in the price of oil, were less than half the cost per unit of heat content of either gas or oil. We could burn oil or gas in a cogenerating station to achieve the high efficiency; however, twice the efficiency at more than twice the fuel cost would not be an economic benefit. Furthermore, such a move would increase our reliance on potentially scarce oil and gas. By the year 2000, 150 to 1000 megawatts of cogeneration could be developed in Ontario. This estimate includes both waste and gas-fuelled plants. At $52/MW.h, the standard cost for gas-fuelled cogeneration is higher than hydraulic, nuclear or the more economic coal options. However, a waste-fuelled plant has a standard cost of $32/MW.h; this is cost-competitive with any supply or demand option.

We are encouraging further development where low cost and waste fuels are available, and where the cost of alternatives is higher. We are offering direct financial assistance to demonstrate how we can work with others to develop economic projects. We will continue to offer technical assistance, provide standby power at no cost, if available, and buy the surplus power from developers and industries using cogeneration.

3.2 Municipal Solid Waste Fuelled Generation (MSW)

Much of the two kilograms of waste we each throw away everyday has energy potential. This potential can be realized by burning the waste to raise steam for the generation of electricity. Presently, one 4 megawatt MSW plant exists in Ontario, and there appear to be several factors which favour further development. These include: the possibility of using older coal generating sites and facilities; potential for cogeneration to supply heat to large commercial buildings; a high volume of waste available close to these sites; and a growing concern with the environmental impact of land-fill disposal. The potential for MSW is limited to about 20 urban areas in Ontario with populations of 50,000 or more. These large population centres provide concentrated sources of waste.

A unique feature of MSW is that, instead of incurring a cost for fuel, it generates revenue from municipalities who pay to dispose of waste. These "tipping fees" are an important component in the cost calculation of MSW. Usually, the larger the city - and thus the greater the value to the municipality of waste disposal - the higher the tipping fee.

High tipping fees and a sufficient concentration of waste exist in a major centre like Toronto. A large MSW plant, in the order of 30-50 MW, would be economical in Toronto because of economies of scale and lower operation, maintenance and administration costs. One plan envisions the conversion of some units at the mothballed Hearn GS, on Toronto's waterfront, to a MSW plant. In this case, the standard cost could be as low as about $30/MW.h. However, there is little further MSW potential at this standard cost.

In smaller cities where there is less waste and lower garbage disposal costs, a MSW plant could not be much larger than 3-5 MW. In this case, the standard cost would be about $70/MW.h.

An existing municipal solid waste plant in Hamilton has drawn public criticism because of the unpleasant odour it produces and the heavy truck traffic required to deliver the waste. Ontario Hydro has evaluated a plant proposal for the city of Ottawa. Opposition was expressed to the expected traffic and air quality problems. Careful attention and expensive equipment are necessary to ensure adequate air quality when the fuel is an unknown mix of waste substances, chemicals, plastics, etc. For successful operation, a MSW plant must have the support of local authorities who receive the garbage disposal benefit.

The future of MSW in Ontario depends on public acceptance and on the availability of sufficient tipping fees and a high degree of cooperation among municipalities, Ontario Hydro and potential steam customers.

3.3 Photovoltaics and Wind Turbine Generators

Both of these technologies generate electricity from energy potential that is spread thinly over a large physical area. A lot of expensive equipment is necessary to gather useful quantities of energy from the sun and wind.

A form of solar energy, photovoltaics were originally developed for use in space. These solar cells convert sunlight directly into electricity. Here on earth, they have been successfully used to serve remote electricity needs such as navigation beacons and telecommunication facilities.

The main advantage of photovoltaics is the flexibility they afford. Since they have short lead times and are modular in design, they can be brought into service as the demand for electricity dictates. However, about 20 acres of land is necessary to produce one megawatt of electricity. The area required to yield the same amount of energy produced by Pickering GS would be about 6 times the area of Metro Toronto. Under most circumstances, photovoltaics are very expensive with standard costs of about $70/MW.h. However, where photovoltaics can replace high cost fuel used for electric generation, they become far more economical.

The wind farm developments in the U.S. demonstrate how some utilities can use wind as part of their resource mix. Most of the wind turbines in the U.S. are located in three California mountain passes. These developments in California flourished in the early 1980s as a result of four factors: the high price utilities pay for electricity, the presence of high winds on undeveloped lands close to transmission, the strong U.S. dollar which reduces the cost of wind generators imported from outside the U.S., and the availability of generous tax credits.

These conditions do not exist in Ontario. In particular, there is an absence of high winds in areas close to the transmission system. Speeds of about 9 metres per second are necessary for economic exploitation of wind resources. In Ontario, wind speeds average about 6 metres per second. The standard cost of a wind turbine in Ontario would be high, at $86/MW.h, because, with low wind speeds, the large facility required generates little electricity. Wind farms, like solar generation plants, require large land areas to generate substantial amounts of power.

We do not expect to use photovoltaics or wind turbines extensively in this century because of their high cost. However, solar and wind may be useful to replace diesel generation in remote communities, not connected to the bulk transmission. As diesel for these remote communities has a minimum standard cost of $95/MW.h, solar and wind generation with standard costs of $71/MW.h and $86/MW.h respectively, are more economic. Wherever wind and photovoltaics are used, back-up facilities will be required for times when the wind is not blowing and the sun is not shining. We have installed a prototype wind generator at Fort Severn in northern Ontario and have already installed two of the largest solar cell power supplies in Canada; one just north of Atikokan, and the other in the remote community of Trout Lake. We will continue to seek appropriate sites for further applications of these technologies.

3.4 Small-Scale Hydro

When we speak of small-scale hydro, we mean sites with less than 2 average megawatts in annual energy production. There are several hundred abandoned or undeveloped small-scale hydraulic sites in Ontario.

The costs and environmental impacts of developing or redeveloping small hydraulic sites depend on a number of site specific details such as the construction of the dam and other civil works, the accessibility of the sites, incorporation costs, and the need to accommodate other users of the river (see 4.2 Hydraulic for further details).

Small scale hydraulic redevelopment is a viable option because much of the construction is completed and sometimes the original generator and turbine can be rehabilitated at low cost. Standard costs for these options are in the area of $27/MW.h. However, standard costs for new small-scale hydro sites are high at $61/MW.h.

In Ontario, the private sector is encouraged to develop the most viable sites. The Ontario Ministry of Energy has surveyed suitable sites and demonstrated appropriate technology at ten of these sites. They also identified sites for private development. Total potential capacity for these small hydraulic sites could be up to 50 MW and perhaps more if favourable economics and incentives continue.

The Ontario Ministry of Energy also hopes to encourage the upgrading of facilities at existing privately-owned sites. The Ministry's target is to promote the development of a total of 100 MW from new and upgraded

privately-owned sites by the year 1995. This is higher than Ontario Hydro's estimate shown on Figure 3.1 because the Ministry includes in its projection sites with a 2 to 10 megawatt capacity. These sites are briefly discussed in 4.2 Hydraulic.

Effective January 1, 1987, Ontario Hydro introduced incentive purchase (buy-back) rates that are higher than the standard rates for purchases from small hydro and other renewable sources. A new financing option has also been provided.

3.5 Wood and Peat-Fuelled Generation

The forest products industry in North America uses large quantities of wood wastes or wood by-products as fuel to generate heat and electricity. Utility-owned wood-fired plants are less common. Two large 50 MW plants exist in Vermont and Washington states. Large plants are necessary for economic generation. The larger the plant, the lower the capital and operating costs per megawatt. However, large plants require more fuel than can be economically supplied. Wood-fuel would have to be collected from distant regions, resulting in an increase in transportation and collection costs, or else tree farms would have to be developed for the specific purpose of providing fuel for the plants.

Although the supply of wood fuel in Ontario is enormous, about 30 million Oven Dry Tons a year, only about 1 million tons could be available for generating electricity. Much of the fuel potential is already being used or is unavailable because of environmental considerations. In future, the available fuel could generate between 50 and 70 megawatts a year in Ontario. Peat resources in Ontario are also enormous but again, because of difficulties associated with harvesting and fuel preparation, the economical supply is limited.

Neither wood nor peat-fuelled generation will likely play a significant role in meeting Ontario's electricity needs except as a fuel in a cogeneration plant. Standard costs for these options range between $73/MW.h and $89/MW.h. We recently participated in the development of an 8 MW wood-fired cogenerating station for Chapleau, which went into service in 1986, by purchasing the power. Similar projects utilizing wood wastes have been proposed for other locations.

3.6 Fuel Cells

A fuel cell is a device which converts the chemical energy of a fuel (e.g., hydrogen) and an oxidant (e.g., oxygen), directly into electricity. The main advantages of fuel cells are their short lead times, low environmental impact, high efficiency and their factory-built and compact modular design. Small 7 to 11 MW plants are being developed which could be implemented by utilities. These plants could replace combustion turbines (see 4.5 Oil and Gas) as a source of generation suitable for supplying short duration peak loads. However, as Ontario Hydro plans to operate few combustion turbines, we do not expect fuel cells to play an important role in helping us meet our electricity needs. Standard costs for fuel cells are high, at $51/MW.h.

3.7 Summary

Most alternative generation options have higher standard costs than either large conventional plants or the most economic demand side options. The cost competitive alternates are large-scale municipal solid waste incineration, some redeveloped small-scale hydraulic sites and cogeneration that can use waste or low cost fuels. Continued technical advances may reduce the cost and improve the performance of fuel cells and photovoltaics.

The potential of alternative generation is considerably less than the projected growth in the demand for electricity. Consequently, we expect the alternatives to play a supplementary role in supplying our electricity needs. The most significant power potential lies in the development of industrial and commercial cogeneration. Alternates are also expected to contribute to the electricity supply in remote, northern communities.

The economics and technology of the alternates are constantly changing. We will continue to study these changes to determine the extent to which the alternatives can meet the demand for electricity in Ontario.

4.0 SUPPLY OPTIONS

This section discusses the value of existing plant followed by a detailed description of the traditional supply options; hydraulic (greater than 2 average MW), Nuclear (single and multi-unit stations), Coal (conversion of Lennox, pulverized coal, and integrated gasification combined cycle), Oil and Gas (subcritical, supercritical and combustion turbine units) and energy storage technologies (above and below ground hydraulic pumped storage, compressed air energy storage and battery storage).

4.1 Existing Plant

The most important category of generating plant over the 20 year planning period is the existing plant. Even at the end of that period existing generation will be more than two thirds of the eventual total. The existing plant is aging and increased efforts will be required to maintain the capability of these plants. In addition, improvements at existing plant can reduce the need for new generating plant, usually at lower cost. Ontario Hydro has replaced turbine runners in 45 hydroelectric generating units in the last 10 years increasing their dependable capacity by 180 MW. The increase in the ratings of nuclear units at Bruce A and Bruce B nuclear generating stations by over 400 MW in total should be completed by 1988. Clearly these efforts should continue.

As existing units age, they can require new expenditures to prevent them from becoming unsafe, uneconomic, environmentally unacceptable, unreliable, etc. The alternative would be to shut down plant but it is frequently more economic to rehabilitate or redevelop older generating plant than to build replacements; two of the most economic hydroelectric opportunities, the Mattagami and Niagara schemes, are redevelopments; one of the least expensive options for coal-fuelled plant is to convert the Lennox oil-fuelled plant to coal; adding limestone scrubbers to existing coal-fuelled plants is one of the measures being considered for implementation by the mid-1990s to help meet acid gas emission regulations; and rehabilitation has been successfully undertaken in the past at a number of stations. The need for rehabilitation and redevelopment is likely to increase in the future as the existing units age while fewer new units are added. Sometimes the need for major rehabilitation provides an opportunity to economically increase output, improve efficiency or make other improvements. These opportunities should be pursued.

Sometimes a plant reaches a point where continued operation is unacceptable and rehabilitation or redevelopment does not seem worthwhile; it would be more economic to replace it with cost effective new plant. At this point, if one could predict the future with certainty the proper decision would be to decommission and dismantle the old plant. However, old plant may still have value to provide flexibility to cover uncertainties in future load growth. It is often possible to recommission an old plant much more quickly than a new plant could be built. The old plant may still be expensive to

operate but cheaper alternatives may not be available. Therefore, a relatively inexpensive strategy to enhance flexibility to accommodate increased load growth is to maintain obsolete old plant in a mothballed state rather than decommissioning it.

4.2 Hydraulic

Expensive to build but cheap to operate, hydraulic plants have provided Ontario with a renewable source of electricity for more than 80 years. Most of the economic sites in Ontario have already been developed. Further hydraulic development depends on the availability of viable, economic sites. A river site must have appropriate hydrological (water flow), geological and water drop features before it can be harnessed for the hydraulic generation of electricity. Although the theoretical potential is quite large, the practical potential that could be developed by the year 2000 lies in the area of 1000 to 2700 megawatts, with an energy potential of 250 to 700 average megawatts; 700 average megawatts is a figure roughly equivalent to the energy capability of one Bruce nuclear unit.

More than any other major supply option, a hydraulic plant's energy production is often well below its peak power capacity. A nuclear or coal plant can be constantly run at full capacity as long as enough fuel is available and the plant does not require repair or maintenance. Water, the fuel of a hydraulic plant, can only be used at the rate supplied by the river. There is simply not enough water in Ontario rivers to drive hydraulic turbines 24 hours a day, 365 days a year. The water can be stored behind a dam and released when required; this way, a hydraulic plant can produce a lot of power in a short time, but it can do so only infrequently after sufficient water has accumulated. A hydraulic plant could be designed to produce a steady output by installing turbines that are matched to minimum river flows. However, this is not economic for most of the remaining undeveloped sites. Potential energy production would be wasted when river flows are high in the spring. Furthermore, the contribution to power production at peak times would be much lower. Consequently, we are only considering hydraulic plants that have a high peak capacity compared to their energy contribution.

These peaking hydraulic plants provide operational flexibility. As each unit of the plant can be stopped and started relatively quickly, we can closely follow the minute-by-minute, hour-by-hour changes in demand. Furthermore, water can be stored behind the dam during lower periods of demand and released when we need generation

Other restrictions exist which limit the use of a hydraulic plant. Hydraulic plants are situated on rivers used by native peoples, cottagers, swimmers, fishermen, industry, shipping and local municipalities. These users expect adequate water levels and flows for their activities. If used indiscriminately, a hydraulic plant can cause levels and flows to fluctuate to such an extent that they would be unacceptable to other users. Flooding due to the construction of new dams and fluctuations in flows due to peaking

operation are of particular concern. Some rivers or stretches of rivers with theoretical hydroelectric potential are not considered part of the practical potential because they have been designated white water parks to preserve them for canoeing enthusiasts. As only one of many users of a river, Ontario Hydro must carefully control the environmental impact of its hydraulic plants.

The largest portion of our theoretical hydraulic potential lies far to the north on four rivers. The Albany and Attawapiskat flow into James Bay; the Winisk and Severn, into Hudson Bay. Although there is a significant volume of water flowing in these rivers, the land over which they flow is flat. The Albany drops only 170 metres over a distance of 450 kilometres. As far as hydraulic potential is concerned, Manitoba and Quebec got the better sides of Hudson and James Bays.

A major drawback of these northern rivers is their distance from a large demand centre. The nearest of the four, the Albany, is still about 600 kilometres north of Sudbury, the closest major demand centre. To deliver the electricity from these rivers to customers in the south would require the construction of transmission corridors through sensitive northern terrain. Measures taken to minimize environmental impact would escalate the costs.

Other less remote sites are more promising. Flowing into Lake Nipigon, the Little Jackfish River is a small but fast river that has a sufficient water drop for a dam. Hydraulic plants already exist on the Mattagami River, flowing into James Bay from the south, but more electricity can be produced from existing water flows. Energy benefits, water flow regulations, and other issues, will have to be negotiated with the Spruce Falls Power and Paper company, owners of an existing hydraulic station on the Mattagami at Smoky Falls. Redevelopment of the Smoky Falls plant is a necessary part of the scheme.

As one of the original stations at Niagara Falls has been closed and another is nearing the end of its useful life, we have the opportunity to develop a new station several kilometres down river near Queenston. This location will allow us to obtain the benefit of the full drop from the falls and rapids.

Ontario Hydro has started studies aimed at obtaining approval to develop the Little Jackfish and redevelop the Mattagami rivers by 1993 and 1994, respectively. Conceptual studies have begun on a new development on the Niagara River with a planned in-service date of 1997. These three sites will provide us with about 1000 megawatts of peak capacity and 250 average megawatts of energy by the time they are completed (Figure 4.1). The remaining 1700 megawatts of the 2700 megawatt projection lie in eleven sites which could be developed by the year 2000. Some preliminary evaluations have been made of these sites. To develop all these sites by that time would severely stretch the ability of Ontario Hydro and other participants to engineer, obtain approvals for and construct so many projects at the same time.

Figure 4.1

Standard Costs For Hydroelectric Options

Sites Greater Than 10 MW	Installed Capacity (MW)	Average Energy (Av. MW)	Standard Cost ($/MW.h)
Mattagami Complex	379	84.8	39
Niagara	532	116.4	42
Little Jackfish	132	64.9	44
Nine Mile Rapids	150	70.7	40
Long Sault Rapids	52	26.9	40
Abitibi Canyon	463	12.6	45
Patten Post	250	43.3	46
Otter Rapids	174	4.9	46
Ragged Chute	104	20.2	46
Maynard Falls	51	26.6	48
* Grey Goose	140	67.3	50
Ear Falls	15	5.4	50
* Grand Rapids	174	71.6	52
* Renison	135	63.3	55
Total	2750	679.0	45 (Avg)
Sites Between 2 & 10 MW	5 - 10	2 - 7	40 - 80

* Assessments have been based on very preliminary information and are subject to wide variation. More detailed site work would be required.

Standard costs are $39/MW.h for the proposed Mattagami redevelopment, $42/MW.h for the Niagara redevelopment and $44/MW.h for the Little Jackfish development. We have also evaluated the standard costs of the other eleven sites which could be developed by the year 2000. These costs range between $40/MW.h and $55/MW.h with a weighted average standard cost for all eleven of about $48/MW.h. Another fifteen medium-sized sites of 2 to 10 megawatt potential were also evaluated in this study. Standard costs for these sites range between $40/MW.h and $80/MW.h with an average of about $50/MW.h. The standard costs of hydraulic plant are based on amortising the high capital costs over an 80-90 year life - a significantly longer life than the 40 year life assumed for coal or nuclear plant.

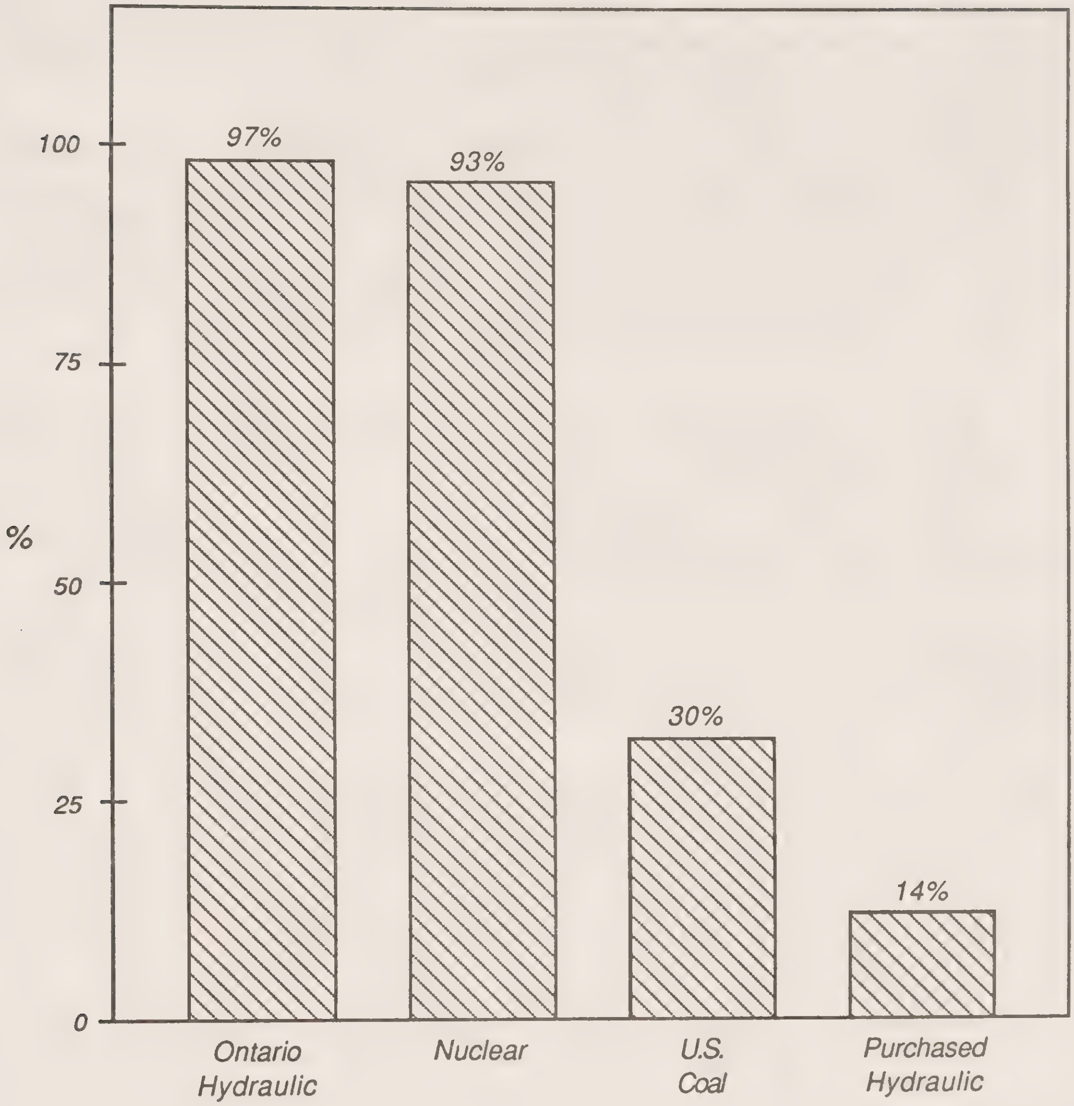
An increase in the discount rate and other capital cost factors would cause standard costs for all the hydraulic options to rise. This rise is not surprising since capital costs are a large proportion of the cost of hydraulic options. If a peaking hydraulic option were added to a base system characterized by a lot of high operating cost generating plant, the standard cost of the option would increase significantly. Again, this is not a surprising result because hydraulic options generally have a capacity factor well below the 68 percent required to meet the average energy demand of the province. In the high operating cost system, a larger part of the additional energy required is made up by expensive-to-operate fossil-fired generation.

Although hydraulic generation does not produce any environmentally hazardous by-products, such as acid gas emissions, it can have untoward environmental and social impacts if it is not adequately controlled. The creation of a reservoir on the up-stream side of a dam can flood land, cause erosion, destroy wildlife and threaten the livelihood of fishermen and tourist operators. However, hydraulic plants can also have a positive impact on the environment: the creation of a reservoir can be used as a recreational facility, and changes in water-flow patterns can assist in flood control.

In both the construction and operational phases, hydraulic options have a good effect on the provincial economy. Almost all the economic activity and job creation occurs in Ontario (Figure 4.2). Since most of the potential hydraulic sites are in remote regions of the province, plant construction can provide a temporary source of employment and economic growth to these regions as a result of indirect economic spin-off.

Compared with other options the lead times for hydraulic options are of medium duration because most of these projects are only of moderate size. Total lead times range from a high of 10 years for some new schemes to a low of 5 years for the extension of an existing site. The definition phase for new sites is 4 years and for existing sites is 3 years.

Figure 4.2
LIFETIME EMPLOYMENT
PERCENTAGES IN ONTARIO



4.3 Nuclear

As a source of inexpensive, reliable electricity, nuclear energy continues to be one of the most economic options available to Ontario Hydro. Further expansion of the nuclear program in Ontario is limited, not by a resource scarcity, but by the length of time required to secure approvals, arrange financing and complete construction.

As a capital-intensive option, nuclear plants are expensive to build, but inexpensive to operate. With these cost characteristics, nuclear plants are used most effectively when they are run all year long as base-loaded resources. These plants are well suited to meet our energy requirements because they are inexpensive to operate: the more they are run, the lower the capital charge per unit of electricity. If we used nuclear plant at only peak times, we would not be using them to full advantage.

Ontario Hydro has extensive and successful experience with the Candu reactor design. Ontario Hydro's reactors have led in performance worldwide. In 1986, out of 236 nuclear units of 500 MW or more in the western world, Ontario Hydro had seven of the top 15 reactors, rated on the basis of lifetime capacity factor. (Capacity factor is a measure of the reactor's operating performance expressed as a percentage of its total potential production if run at full capacity without interruption.) Ontario Hydro's Candus are successful because of good design and operation and a feature which permits refuelling without stopping or slowing the reactor process. Although nuclear alternatives to the Candu are available, they offer few advantages.

A significant cost feature of nuclear plants is their economies of scale: both capital and operating costs decline per installed megawatt of electricity produced as we move from single unit, small stations to multi-unit, large stations. Four-unit stations with large reactors utilize engineering, supply, construction and project management services more economically. Operation, maintenance and administration costs also decline per installed megawatt for the four-unit stations. Standard costs (Figure 4.3) range from a low of $32/MW.h to $36/MW.h for the four-unit stations with reactor sizes of 540 MW to 1250 MW, to a high of $41/MW.h for the single unit, 740 MW option and $51/MW.h for the Atomic Energy of Canada, single unit, 400 MW option. (The unit sizes and standard costs of the single unit 400 MW and 740 MW stations are based on new information. These data supersede those previously quoted for single unit stations in documents 651SP, "Meeting Future Energy Needs - An Initial Review of the Options", November 1985 and 652SP, "Demand Supply Options Study - The Options", February, 1986).

Standard costs are significantly affected by changes in the discount rate and capital costs. An increase in the discount rate from 4% to 6% increases the standard costs by about 27%; a 20% change in capital costs would change the standard costs by 14%.

Figure 4.3

Standard Costs For Nuclear Options

Design * Similar To	Unit Size (MW)	Number of Units per Station	Station Size (MW)	Standard Cost ($/MW.h)
New AECL Design	400	1	400	51
Point Lepreau	740	1	740	41
Pickering B	540	4	2160	36
Darlington	881	4	3524	32
Darlington ** (extended schedule)	881	4	3524	34
New	1250	4	5000	32

* Estimates are based on experience with existing stations; however, actual sites have yet to be determined.

** In-service interval of 24 months between units instead of the standard 9 months.

These results are typical of capital intensive options and point to the financial risk of making large capital outlays. Standard costs increase when a high capital cost, low energy cost generation system is assumed. In this case the system already has a large quantity of high capital cost, low energy cost generation; consequently, it is not cost effective to add additional plants of this kind. On the other hand, when we consider adding nuclear energy to a low capital, high operating cost system which relies on expensive oil-fuelled plant, the standard cost of nuclear energy declines because this system needs additional low cost energy for a more economical mix.

Any major construction undertaking will have significant environmental impact if not well-managed, and the construction of nuclear plants is no exception. During the operation of nuclear plants, large volumes of slightly warm, non-radioactive water used for cooling are expelled into lakes. This can affect the ecological balance of the lake. Cooling water out-flows and intakes must be carefully designed to minimize the environmental effects.

At the heart of the debate about the environmental impact of nuclear energy is the public concern over radiological issues from uranium mining to waste management and plant decommissioning. Radioactive emissions from Candu reactors are controlled to a very low level: normally less than one percent of the regulatory limit. No permanent disposal site for used fuel yet exists. Presently, used fuel is stored at the plant site in fuel bays. While this is a safe and inexpensive method of storage which can be relied on for several decades, plans are underway to develop an ultimate disposal method for the used fuel from Canadian reactors. One possible solution is to place the used fuel deep in a geologically stable region of the Canadian Shield.

Lead times for nuclear plants are among the longest of any of the options available. Although some multi-unit projects can take as long as 16 years from conception to completion of all four units, power would be available from the first unit after 13 years. This would be 8 years after the start of construction and associated major expenditures. These long lead times limit the flexibility of a system with a large component of nuclear generated electricity to accommodate unforeseen changes in demand but during the conception/approval phase the start of construction could readily be delayed to adjust to a slower rate of load growth or other such circumstance. However, if demand grew more slowly than expected during construction and we found ourselves with surplus capacity, we would use nuclear plants to replace fossil-fuelled generation to save on the costs of these fuels.

Smaller unit sizes would afford greater flexibility, but, as we have seen, they are more expensive. Greater flexibility could be achieved at a modest increase in cost if a large multi-unit station were committed for construction one or two units at a time. Modified construction methods might shorten the time between financial commitment and in-service date.

Reasonably priced Canadian uranium will be available well into the next century from Elliot Lake in Ontario and recent discoveries in Saskatchewan.

Since its fuel is indigenous to Canada, nuclear energy is not sensitive to the inflation of international energy prices. Also, any rise in the price of Canadian uranium will have little effect on the cost of nuclear energy because fuel costs are not a large component of the cost of generating nuclear electricity.

The effect of an expanded nuclear program on the provincial economy would be at least as good as any other option (Figure 4.2). The mining of uranium could take place in Ontario or Saskatchewan, but fuel refining, fuel fabrication, construction, heavy water production and plant operation would all take place in Ontario. These activities would create jobs and economic spin-offs for the province.

The safety of CANDU nuclear reactors in Ontario is currently being reviewed. The Select Committee on Energy, in its July 1986 report, recommended that the scientific and engineering aspects of nuclear safety be examined. In accepting this recommendation, the Ministry of Energy appointed Dr. F.K. Hare as Commissioner of the Ontario Nuclear Safety Review, in December 1986. The commission is to review the CANDU design, Hydro's nuclear plant operating procedures, and the procedures for emergency response. A report from the commission is expected by the end of February 1988.

4.4 Coal

As a medium-cost source of electricity, coal-fired generating plants are used to meet our electricity needs after cheaper, base-loaded hydraulic and nuclear plants are utilized. Like the nuclear option, the potential for coal-fired plants is limited by the length of time needed for approval and construction. It takes 12 years from conception until a four unit coal-fuelled station can be completed; 10 years is needed to get the first unit into service. The start of construction and associated major expenditures would occur 5 years prior to the in-service date of the first unit, and like nuclear these long lead times limit flexibility. However there is also an assumption that we will find satisfactory answers to some difficult questions about the future of coal-generated electricity in Ontario. How can we expand our coal program and maintain our commitment to reducing acid gas emissions? Are the new emission control technologies reliable and cost-effective? Will the price of coal rise? Should we be committing ourselves to a source of generation which uses a fuel supplied and controlled by forces outside of Ontario and Canada?

About 37 percent of our total power producing capacity is coal-fuelled. These plants are used to generate about 25 percent of our electrical energy. A problem that has become more significant in recent years concerns the emissions from coal-fuelled plants which contribute tc acid rain. Ontario Hydro is only a small contributor to acid gas deposition in sensitive areas in Ontario (4 percent). Nevertheless, we are committed to reducing our annual system wide emissions of sulphur and nitrogen oxides from more than 500,000 tonnes a year to less than 215,000 tonnes in stages by 1994. All coal-fuelled options are evaluated on the assumption that sufficient control measures are used to meet this regulation; the additional cost of meeting the regulation is part of the standard cost of coal

options. If stricter acid gas emission regulations are imposed, the standard costs of coal options will tend to rise.

There are a number of coal-fuelled options available to meet future energy needs (Figure 4.4).

Pulverized Coal Combustion

All of Ontario Hydro's coal-fuelled units use pulverized coal combustion. In this process, the coal is ground to a fine powder and blown into a furnace where it burns creating hot combustion gases. These gases pass over a series of pipes containing water which boils to raise high temperature and high pressure steam. The steam drives a turbine which in turn drives an electrical generator. After passing through the turbine, the steam is condensed to water. A great deal of water from a large lake (or river) is required to condense the steam. This cooling water is returned to the lake with a sightly higher temperature than it had when it was brought in. After passing through the boiler, the exhaust gases are emitted to the atmosphere through a tall stack. These gases contain sulphur oxides and nitrogen oxides.

At present, Ontario Hydro has no equipment on its plants to remove the oxides of sulphur from these gases. These emissions are currently controlled by using lower sulphur coal and by generating less energy from coal. Ontario Hydro will achieve the required reductions in emissions by using a combination of these methods in conjunction with new and relatively untried technologies. The commercially proven equipment available today for removing oxides of sulphur consists of several types of flue gas scrubbers. The addition of these scrubbers will require major plant modifications with costs equal to about 15 percent of the cost of a new plant. In the most common type, the wet limestone scrubber, wet limestone reacts with flue gas to remove up to 90 percent of the sulphur oxides. The process produces a residue of wet sludge. Disposing of this sludge poses significant technical and environmental problems.

Another method of removing sulphur oxides, furnace limestone injection, is being investigated by Ontario Hydro at Lakeview Generating Station. This technique is neither fully proven nor commercially available. In this process, a dry limestone powder is sprayed into the combustion gases inside the furnace. Dry limestone injection has two advantages over wet scrubbers: capital costs will likely be less, and the residue produced by the injection process is a dry powder mixed with ash. This residue is more easily disposed of than the sludge produced by the wet scrubbers. However, the amount of sulphur oxides removed by the injection process is only 40-50 percent of the total. The dry scrubbers would likely be added to older, infrequently used units near the end of their life span. Used in this way, the low capital cost dry scrubbers are economically preferable to the high capital cost wet scrubbers.

Nitrogen oxides also contribute to acid gas emissions. All fossil fuel combustion produces nitrogen oxides. Ontario Hydro is limiting nitrogen oxide emissions by installing modified burners at Nanticoke GS. These reduce the temperature of the flame and thereby limit the formation of nitrogen oxides.

Figure 4.4

Standard Costs For Coal Options

Coal Option*	Unit Size (MW)	Number of Units per Station	Station Size (MW)	Standard Cost ($/MW.h)
LENNOX CONVERSION				
- Existing Boiler	350	4	1400	42
- New Boiler	500	4	2000	40
PULVERIZED COAL COMBUSTION				
- Subcritical	200	1	200	63
	200	4	800	52
	500	1	500	52
	500	4	2000	44
	800	1	800	50
	800	4	3200	44
- Subcritical Burning Western Canadian Lignite	200	1	200	72
	200	4	800	63
- Supercritical	500	1	500	55
	500	4	2000	47
	1000	1	1000	51
	1000	4	4000	43
	1300	2	2600	45
INTEGRATED GASIFICATION COMBINED CYCLE	200	1	200	58

* Except as noted, all options assumed to burn US Bituminous Coal.

A number of pulverized coal burning options have been evaluated including a variety of combinations of unit sizes and numbers of units per generating station. Options identified as subcritical use steam at temperatures and pressures similar to existing modern Ontario Hydro units. Other utilities operate supercritical units which use higher temperatures and pressures and require a different kind of boiler. The efficiency of these units is slightly higher, but they offer less operational flexibility. Supercritical units are best suited to very large unit sizes that operate for long periods with little change in load.

Lennox Generating Station, an existing oil-fired station, could be converted to a pulverized coal unit. If modified burners in the existing boiler are used to fire the coal, the output of each unit will be reduced from 500 megawatts to 350 megawatts. However, the full 500 megawatts can be maintained if extensive modifications are made to replace the existing boilers with larger coal-fuelled boilers.

Atmospheric Fluidized Bed Combustion (AFBC)

In various stages of development for the last 10 to 20 years, this different method of burning coal has not yet been successfully applied to large utility boilers. In a fluidized bed plant, sufficient air must be blown into a mass of powdered coal and limestone particles for them to act as a liquid. The combustion takes place in the bed generating heat; pipes carry water through the bed, converting the water to high pressure, high temperature steam. The turbines and generators are then driven in the same way they are in a pulverized coal plant. No separate acid gas controls are necessary because the limestone mix in the bed permits the removal of the sulphur oxides as the combustion occurs. Furthermore, the AFBC produces a smaller amount of nitrogen oxides because combustion in this type of boiler takes place at lower temperatures.

Atmospheric fluidized bed technology may be useful in the next 20 years to rehabilitate old coal-fuelled plants having smaller units. However, it is unlikely to be fully developed in commercial sized units of 200 MW or larger in time to be in service within the next 20 years.

Integrated Gasification Combined Cycle (IGCC)

This alternative method for burning coal is closer to commercial development than fluidized bed combustion. A 100 megawatt demonstration unit is now operating in California. In this process, coal is converted to a combustible gas which is then burned in a combustion turbine. These turbines are very similar to a jet aircraft engine: in a jet, the gases are used to propel the aircraft forward; in a combustion turbine, the gases are funneled into a turbine to generate electricity. After going through the gas turbine, the gases are still hot enough to boil water in a waste heat boiler, creating high temperature, high pressure steam. This steam can be used to generate more electricity in a steam turbine.

There is also heat generated in the gasification process. This heat can be used in the steam part of the cycle to improve the efficiency. This process offers the least acid gas emissions of all the coal burning technologies. It also offers some potential for increased flexibility because if an unanticipated need arises, the combustion turbine and steam turbine could be built quicker than the total plant and operated on natural gas or oil until the gasification part of the plant could be completed. The gasification facilities are, in effect, a small chemical plant. These facilities require large areas of land and introduce additional operational complexity.

Standard Costs

Standard costs (Figure 4.4) are lowest for large, multi-unit pulverized fuel combustion plants and highest for small, single unit plants using unconventional technology. The standard cost range reflects economies of scale for all coal options; the larger the plant, the cheaper the unit of energy produced. For example, the 4x1000 megawatt pulverized fuel combustion plant has a standard cost of $43/MW.h; the standard cost of a smaller, but similar plant, is $63/MW.h.

Standard costs for the coal options are affected by changes in the capital cost factors. An assumed rise in the discount rate from 4 to 6 percent shows a 15 percent increase in standard costs. Increasing the capital cost estimate by 20 percent for established technologies and 30 percent for new technologies results in a 6 to 8 percent increase in standard costs.

As capital intensive projects, coal plants have long lead times, ranging from a low of eight years for the 1x200 MW IGCC and the Lennox conversion option, to a high of fifteen years for the 4x1000 MW supercritical plant. In general, lead times lengthen with increases in station size. The Integrated Gasification Combined Cycle plant does afford some flexibility compared to other coal options. Because it is modular in design, it can produce electricity before the entire plant is completed.

Adequate coal reserves exist to supply all of Ontario's coal-fired options. The cost of coal-fired electricity is very sensitive to increases in coal prices which are determined by forces beyond our control. Since most of our coal is imported from the United States, much of the economic and job creation activity associated with coal-fuelled generation occurs outside of the province and Canada (Figure 4.2).

4.5 Gas and Oil

After the oil crisis of the early 1970s, gas and oil-fuelled generation became increasingly expensive until the 1986 sharp drop in world oil prices. Except for a few specialized applications, most utilities turned to other sources of generation whenever they could. One of the reasons the cost of electricity is so high in the United States is because many

utilities remain dependent on gas and oil-fuelled generation. Ontario Hydro has been able to avoid these high electricity costs because we have never been highly dependent on oil or gas. Most of the oil and gas-fuelled generation on our system is now mothballed. These plants could be used in the future to meet short duration peak power needs. As we expect oil and gas to become scarcer, we do not intend to become heavily dependent on either of these generation types. The oil and gas options examined in this study would only be considered for a highly selective role.

A variety of gas and oil options, of various sizes and kinds, were examined (Figure 4.5). A total of eighteen gas options were studied, but only four oil options were given initial consideration because of the high cost of fuel. Capital costs for oil and gas plants are not high: capital costs for a gas plant are 45 percent less than the capital costs for an identically sized coal-fuelled plant. However, natural gas was more than twice the price of coal at the time of this study, and further increases in price are expected throughout the 1990s.

After the initial study, we eliminated most of the oil and gas options from further consideration on the basis of cost. Three options remain for further consideration: the operation of Lennox Generating Station with oil, the conversion of Lennox to burn gas; and a variety of sizes and designs of combustion turbines. (Two of the four units are being readied for possible operation during the 1987/88 winter for system reliability purposes. It is not yet decided how long this particular need will last.)

Combustion turbines are oil or gas-fuelled options which operate in a manner similar to the operation of a jet aircraft engine (see 4.4 Coal; Integrated Gasification Combined Cycle Plant). These combustion turbines have very high fuelling costs, but they are relatively inexpensive to build. With three years required for design and approval, and two years needed for construction, combustion turbines have one of the shortest lead times of all the available supply options. Three sizes of combustion turbine plants have been examined: small emergency units of 10 and 25 megawatt capacity; medium sized units of 100 megawatt capacity; and large combined cycle units of 200 megawatt capacity.

In a combined cycle plant, the basic unit is a combustion turbine. A waste heat boiler is added to use the heat from the exhaust gases to raise high pressure, high temperature steam. This steam drives a steam turbine which produces additional electricity. The combined cycle plant can produce electricity at higher efficiency than either a single combustion turbine or a single steam turbine. However, this high efficiency plant burns an expensive fuel. The chief advantage of the combined cycle plant is the flexibility afforded by its modular design: the combustion turbine can be built first and used to generate electricity before the steam turbine is added.

Figure 4.5

Standard Costs For Gas And Oil Options

Gas Option	Unit Size (MW)	Number of Units per Station	Station Size (MW)	Standard Cost ($/MW.h)
LENNOX CONVERSION	500	4	2000	42
SUBCRITICAL	200	1	200	57
	200	4	800	53
	500	1	500	52
	500	4	2000	49
	800	1	800	50
	800	4	3200	48
SUPERCRITICAL	500	1	500	54
	500	4	2000	50
	1000	1	1000	52
	1000	4	4000	49
	1300	2	2600	50
COMBUSTION TURBINE UNITS				
- Emergency Use	10	2	20	49
	25	10	250	47
- Planned Industrial	100	2	200	44
	100	10	1000	44
- Combined Cycle	200	2	400	47
	200	8	1600	47
Oil Option				
LENNOX	500	4	2000	43
SUBCRITICAL	500	4	2000	56
COMBUSTION TURBINE UNITS				
- Emergency Use	10	2	20	50
	25	10	250	48

Standard costs for combustion turbine and combined cycle plants vary according to the mix of generation on the system. If the system has the generation mix we expect, the standard costs for the combustion turbines and combined cycle plants range from a low of $44/MW.h to a high of $49/MW.h. With these standard costs, the gas-fuelled options are not much more expensive than coal options. In the low capital system, a lot of oil and gas-fuelled options are already in operation. In this case, the addition of more combustion turbines or combined cycle plants is not economical. The standard cost of the addition of a gas-fuelled option to this system is about $58/MW.h.

If we do not rely heavily on combustion turbines or combined cycle plants for expected conditions, we can take advantage of the flexibility they offer to meet higher than expected load growth.

The two Lennox options are the only other economically feasible oil and gas possibilities. The chief advantage of operating Lennox to burn oil is that the plant already exists and is designed to burn oil. Although oil is expected to be expensive, this option is competitive because there are no significant new capital costs. The standard cost of operating Lennox on oil is $43/MW.h.

At $42/MW.h, the standard cost of converting Lennox to burn gas is slightly less than the Lennox oil option. Even though there are some capital costs for conversion to gas, the cost of natural gas at the time of this study was sufficiently less than the cost of oil to make the Lennox gas option marginally more attractive. Whether it is converted to gas or operated with oil, Lennox would only be used infrequently to meet load during short duration peak demand periods.

The conversion of Lennox to a coal-fuelled option is also being considered (see 4.4 Coal). The standard costs of the two coal conversion options are $40 and $42/MW.h. We would not build an oil-fuelled station like Lennox today but, since the station already exists, it has a potential we can exploit if necessary by operating it on oil, or by converting it to a cheaper fuel such as coal or gas.

Fuel Supply

Sufficient supplies of natural gas from eastern and western Canada are expected to be available for the rest of this century. However, it is unlikely that the supply or government policy will permit large purchases of fuel for a multi-unit generating station. We may be able to obtain sufficient gas to drive combustion turbines or Lennox for short duration peak periods. With intermittent use of this kind, we should expect a price premium to be applied to any gas purchase contract.

Due to the tendency to upgrade crude oil to more valuable products, we cannot be sure there will be sufficient quantities of residual oil for generation on the scale of Lennox. We expect the price of oil to rise faster than the rate of inflation through the 1990s making oil-fuelled generation expensive.

4.6 Energy Storage Technologies

Electricity demands vary; daytime is higher than nighttime; weekday is higher than weekend; winter is higher than summer. Since electricity cannot be stored, electricity production must follow the demand, minute by minute, hour by hour, throughout the year. This means that there is usually under-utilized electrical capacity at off-peak times, because the electricity system must be large enough to reliably meet the peak demand. Although electricity cannot be stored, other forms of energy can be stored. By making use of electricity generators that would otherwise be idle, energy storage options absorb electricity during low demand periods, usually at night. This energy is converted into another form and then stored. In the daytime, the reverse process converts the energy back into electricity.

Energy storage options might contribute 1000 MW to peak power needs by the end of the century, but would not make any contribution to meeting energy needs. In fact, since all conversion processes have some inefficiencies, energy storage options consume more energy than they produce. Some energy is lost in the storage and conversion processes. The 1000 MW potential is limited by the expected availability of under-utilized plant at nighttime. If other energy limited options are implemented -- load shifting, peaking hydraulic -- then the potential for energy storage is reduced.

Energy storage options can reliably supply an increase in peak power demands. When demand is well below the peak at night, they would be operated in the storage mode to allow energy from unused, low cost nuclear generation to displace higher cost coal generation in the daytime. Some forms of energy storage have operational advantages because they can start power production relatively quickly.

A number of different energy storage options have been studied (Figure 4.6).

Above Ground Pumped Hydraulic Storage

This most common form of energy storage has been widely used in many countries. In above-ground pumped hydraulic storage, electricity is used at night to pump water from a lower reservoir to an upper reservoir. Energy is stored as the potential energy of water at a higher elevation. A peaking hydraulic plant also effectively stores energy in the same form by storing water behind a dam at night for use in the day. The pumped hydraulic storage or the peaking hydraulic plant generates electricity in the daytime by allowing the water to fall through a turbine which drives an electric generator. As the electrical energy generated is only about 70% of the energy used to pump up the store of water at night, the pumped storage process is only about 70% efficient. However, the peaking hydraulic is almost 100% efficient as an energy store because the amount of electricity generated by the water during the day is almost the same as if the water had been used at night.

Figure 4.6

Standard Costs For Energy Storage Technologies

Energy Storage Technology	Installed Capacity (MW)	Standard Cost ($/MW.h)
ABOVE GROUND PUMPED STORAGE		
- Matabitchuan	405	52
- Jordan/Erie	1125	48-56
- Delphi Point	2082	50-51
UNDERGROUND PUMPED STORAGE		
- Pickering	2000	48-59
- Lakeview	2000	57
COMPRESSED AIR ENERGY STORAGE	220	52
BATTERY STORAGE	200	166

Note :

Net energy production for these options is negative due to inefficiencies in the conversion of the electrical energy to other forms of energy for storage and later reconversion to electricity.

In a pumped storage plant, it is not necessary to have separate pumping and generating equipment; the turbine generator can do double duty as a motor-pump to pump the water up to the reservoir.

Ontario Hydro already has a small above-ground pumped storage plant at Niagara. Three additional sites have been considered in this study: Delphi Point near Collingwood, Matabitchuan near Lake Timiskaming, and the Jordan/Erie scheme between Lake Ontario and Lake Erie. The most promising of these is a 2000 MW scheme at Delphi Point. Here, Georgian Bay would be the lower reservoir and an upper reservoir would be constructed on a suitable adjacent hill. This site might draw public criticism because of its appearance. The upper reservoir would require careful landscaping because it would be a fairly prominent feature of the landscape. A new transmission corridor might have to pass through recreational areas near Collingwood and eventually cross the Niagara Escarpment. Other environmental impacts are similar to those caused by hydraulic projects, except that the pumped storage plant would not affect the flow of a whole river system.

Underground Pumped Hydraulic Storage

Underground pumped storage differs from the above-ground variety because a lower reservoir would have to be dug out of a deep hard rock formation. Although underground storage has not been used before, it is not an entirely new technology: it uses existing mining and hydroelectric technologies. The advantages of underground pumped storage include: less visual impact than above-ground pumped storage, and the presence of suitable sites and sources of pumping power near the largest load centre, the Toronto area. Surprisingly, underground pumped storage is likely to be cheap if the price of gravel in the Toronto area is high. The rock that is dug out of the ground to make the underground cavern can be used as aggregate in concrete for most building applications. Since the proposed sites are in the Toronto area, this aggregate can be sold to the Toronto construction industry. If builders could use the gravel from cavern excavation, they would not need to truck gravel from more distant sites. This would diminish the need for environmentally disruptive open gravel pits. The revenue from the sale of gravel could pay for a large part of the costs of excavating the cavern.

The proposed sites for underground pumped storage are the existing Ontario Hydro generating plants at Lakeview and Pickering. In both cases, the upper reservoir would be Lake Ontario and the lower reservoir would be excavated in hard rock called the Gull River Limestone formation. The lower reservoir could be 300-1300 metres below ground level. The greater the depth, the smaller the cavern needs to be for the same energy storage. However, the deeper schemes may have more technical problems to solve. The amount of gravel produced would still be very large: The 2000 MW scheme with a deep cavern at Pickering would produce 7 million cubic metres of gravel, enough to supply the needs of Toronto for up to 10 years. And this is the smallest cavern of any of the proposals. Because most of the facilities would be underground at an existing Ontario Hydro generating plant, the environmental

impact would be relatively small. Transmission requirements would also be small due to the proximity to a major load centre and the existing transmission and switching facilities.

Compressed Air Energy Storage

Another medium for storing energy is compressed air. The compressed air is stored in an underground cavern and is used in conjunction with a combustion turbine unit (see 4.4 Coal: Integrated Gasification Combined Cycle Plant). A normal combustion turbine has a compressor which compresses the air before combustion with oil or gas. The hot gases produced by the combustion of fuel and air drive a power turbine; part of the power from the power turbine is used to drive the compressor while the rest is used to generate electricity.

In a compressed air energy storage plant, electricity from the system is used to drive the compressor at night and create a store of compressed air. The compressed air is stored underground until the next day when additional electricity is needed. The air is then released to burn with oil or gas in the combustion turbine; all the power that is generated as the combustion gases pass through the turbine can be used to generate electricity since there is no need to drive the compressor.

If this option is used frequently, then it increases the system's dependence on scarce oil or gas. Compressed air storage can not economically store surplus nuclear energy at night to save the use of coal during the day, because it requires the use of oil or gas. However, it can economically store energy from coal at night to reduce the use of oil or gas during the day.

The efficiency of compressed air storage is about the same as the normal 70% efficiency of above or underground hydraulic storage.

Only one compressed air storage plant exists in the world. It can generate 290 MW and was built in 1978 at Huntorf in West Germany where it has provided a highly reliable source of peaking generation. The cavern at Huntorf was created by water leaching in deep salt deposits. A suitable cavern could also be mined in hard rock or in suitable deep aquifers (water bearing rocks).

Environmental effects of compressed air storage would depend on the type of cavern used. Leaching of salt deposits could have problems of brine disposal, and aquifer storage could cause some ground water contamination.

A 220 MW plant was evaluated in this study. Its standard cost calculation assumes a close proximity to a load centre, so that it would not contribute to major transmission requirements.

Battery Storage

Electrical energy can be converted to chemical energy and stored in a battery. The most common form is the lead acid battery similar to a large bank of car batteries. This is the only technology that is sufficiently developed to be considered for commercial application. The main disadvantage of these batteries is that they only last about four years because the cycle of energy depletion and replacement gradually wears out the devices. This study assumed that with some additional research, the lives could be extended to six years. Storage batteries would have very little adverse environmental impact.

Standard Costs of Energy Storage Options

All the energy storage options have standard costs in the $48-59/MW.h range except for batteries which at $166/MW.h are very expensive. The hydraulic options tend to be limited by the time available to pump overnight: a 10 hour pumping period is not sufficient for the 14 hours of generation during high load periods. Schemes with greater storage tend to have better economics because the energy pumped on the weekend can be used to supplement generation on the week days. One of the lowest cost options is the deep cavern underground pumped storage scheme at Pickering, assuming that revenue from the sale of additional aggregate will cover the cost of making the cavern bigger. If the aggregate cannot be sold, all underground pumped hydraulic storage schemes would be in excess of $70/MW.h.

The standard costs of hydraulic energy storage options, both above and underground, are particularly sensitive to the market for exporting surplus nuclear energy. Surplus nuclear energy can be sold or stored. If there is no profit from selling it, the standard costs of storage options improve by about $5/MW.h. The cheapest option is reduced to $43/MW.h which is comparable to some of the better coal-fuelled and hydraulic options.

The size of most of the above-ground and underground hydraulic schemes, at about 2000 MW, is large compared to the need for energy storage. The standard costs of some options are higher because their full capabilities cannot always be used.

4.7 Summary

Hydraulic

A large portion of the theoretical hydraulic potential in Ontario lies far to the north on 4 rivers draining into James Bay. The extensive flooding that would result from harnessing these rivers, as well as the larger amount of transmission that would be required to bring the electricity to our customers, excludes these rivers from further consideration at this time. The most likely sites for development by the year 2000 include the Little Jackfish, the Mattagami and the Niagara Rivers.

Nuclear

Of the nuclear options considered in this study, the 4x1250 megawatt option is not retained for further study even though it has a standard cost equal to the lowest of all the nuclear options. As a prototype, it requires further developmental work before it can be considered available. Because it has a long lead time and involves commitment of a large block of power, the 4x1250 megawatt station would be inflexible for adjustment to unforeseen reductions in the demand for electricity.

Despite its shorter lead time and the flexibility it affords, the 1x400 megawatt option is also dropped from further study. It has the highest capital and operating costs of all the nuclear options. As a prototype, like the 4x1250 megawatt option, the 1x400 megawatt station requires further developmental work.

Options retained for further study include the 1x740 megawatt Point Lepreau design, the 4x540 Pickering B design and the 4x850 Darlington design. Although the 1x740 station is the most expensive of the retained nuclear options, it is the best single unit station design. With the exception of the 4x1250 station, the 4x540 and 4x850 stations are the least expensive nuclear options and therefore merit further study.

Coal

Although the AFBC technology has a low environmental impact, it cannot be considered for implementation in the next twenty years because economical unit sizes will not be developed. However, it may be more feasible to convert existing small-unit plants - Hearn, Keith - to AFBC. Such conversions would eliminate the need to add full scale flue gas desulphurization to these existing pulverized coal combustion plants. IGCC plant, also a developing technology, is not cost competitive at this time either. However, its short lead times and slight environmental impact may outweigh its cost disadvantage in certain situations. As larger sizes are developed, the costs may become competitive with pulverized coal plant. Nevertheless, there are risks involved in committing ourselves to a less than proven technology. The most cost effective coal options are the Lennox conversion option and the multi-unit pulverized coal combustion plant.

Oil and Gas

Generating electricity from oil or gas has been expensive until recently, and is expected to become expensive again because of the limited quantity of reserves. Any oil or gas-fuelled option should be used to meet short duration peaks. Both Lennox and combustion turbines could provide us with some capacity for this purpose. If we avoid relying too heavily on these plants to meet our expected conditions, they could be useful as a source of flexibility to meet higher than expected load growth.

Energy Storage

Battery storage options will not be studied further at this time because of poor economics due to a short life. Above ground and underground hydraulic pumped storage schemes have been retained for further study, although their standard costs are somewhat higher than many of the major supply and demand options. The economics of underground pumped storage depend on the market for aggregate in the Toronto area. Hydraulic pumped storage is more economic if the market for selling unused nuclear energy in the U.S. or elsewhere is poor. Compressed air storage is retained for further study because of its small size and siting flexibility which can reduce the need for extra transmission.

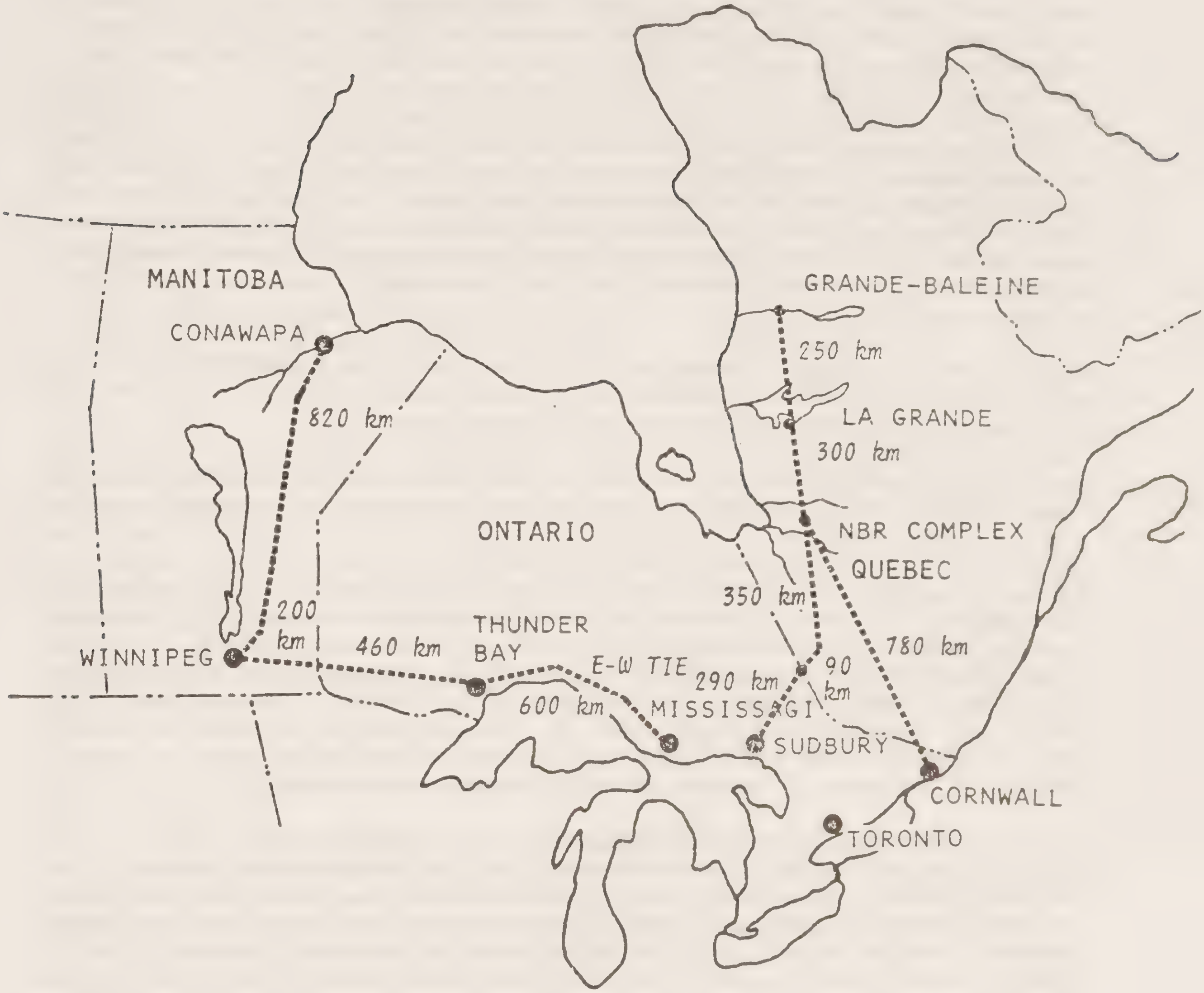
5.0 PURCHASES

Alternative sources of hydraulic power for Ontario Hydro lie to our east and west -- in Quebec and Manitoba. With large volumes of fast flowing water, the northern rivers of Quebec and Manitoba have excellent hydraulic potential. Ontario Hydro has contacted Manitoba Hydro and Hydro-Quebec and both utilities have expressed interest in negotiating a long-term purchase contract. Studies and contract negotiations are now in progress. A Quebec purchase of about 750 megawatts, 2000 megawatts and even up to 4000 megawatts is being considered. Such a purchase would require the development of hydraulic plant in northern Quebec: possibly in the area drained by the Nottaway, Broadback and Rupert rivers (the NBR Complex) or in an area 300 kilometres further north on the La Grande River, near the existing James Bay Project, or even 250 km further north on the Grande Baleine River. For a large purchase, the construction of additional transmission facilities is necessary in both Quebec and Ontario; a small purchase could be supplied largely with existing transmission lines from existing stations on the Ottawa River. Purchase sizes of 200 megawatts and up to about 1000 megawatts are being considered in negotiations with Manitoba Hydro. The power could be generated from the proposed Conawapa Generating Station on the Nelson River in northern Manitoba.

The chief advantage of a purchase is that it allows Ontario Hydro access to some of the best hydraulic potential in the world. However, it is important to realize that Ontario Hydro would not be purchasing large quantities of electricity from existing generating facilities. Neither Quebec nor Manitoba expect to have surplus capacity in the 1990s. Therefore, a purchase by Ontario Hydro means that the selling province would have to construct hydraulic plant and extensive transmission facilities. Since Ontario Hydro's system cannot presently accommodate a large import of electricity from either of our neighbouring provinces, we would have to make extensive additions to our interconnection lines and internal transmission. These developments would be expensive for both the selling province and Ontario Hydro. A large purchase from Manitoba, for example, would require the construction of a new hydraulic plant on the Nelson River; from there the power generated would be transmitted via Winnipeg to Thunder Bay by major new transmission lines; to receive the power and ensure the stability of Ontario's system, we would have to strengthen our transmission lines from Thunder Bay to Sudbury. A large, 2000 megawatt purchase from Quebec would require the construction of high capacity transmission lines from the generating source in northern Quebec to a suitable point in Ontario, possibly near Sudbury or the Ottawa/Cornwall area. If Sudbury is chosen as the terminal, then major transmission facilities would have to be developed in Ontario as well. A large purchase of 4000 megawatts would require major transmission into both Sudbury and the Ottawa/Cornwall area. The delivery of a smaller 750 megawatt purchase would probably not require major new transmission lines in either province.

Transmission distances for purchases from both Manitoba and Quebec are shown in Figure 5.1.

Figure 5.1
NEW TRANSMISSION REQUIREMENTS FOR PURCHASE OPTIONS



It is not yet clear how much Ontario Hydro would have to pay for these developments. Several factors make accurate cost estimating difficult. We do not have details of the cost data because most of the costs are incurred outside of Ontario. Our estimates of these external costs are not based on direct experience, but on indirect information. The final price of the purchase -- the cost to Ontario -- is being negotiated with the selling province.

Three main price factors would determine the final price to Ontario Hydro of a power purchase. The first concerns the selling province. For Manitoba Hydro or Hydro-Quebec to be interested in a sale, the final price must be greater than their costs. These costs would include all of the expenses associated with plant construction, plant operation and transmission line development. The margin between cost and price would be a profit for the seller.

The second price factor concerns Ontario Hydro. From a cost perspective for us to be interested in a purchase, the price must be less than the cost of any similar, alternative option that is available.

A transaction would only occur then, if the price set is greater than the seller's cost and less than the cost to Ontario Hydro of any similar and available alternative.

There is a third factor, however, which would also influence the price of the option. Manitoba is currently negotiating with several U.S. interests for the sale of the power to be generated at the Conawapa site: the same power which interests Ontario Hydro. Quebec is also considering further sales to New England and New York. If the cost to these competitors of their next available option exceeds the cost of Ontario Hydro's alternative, then the competitors would likely drive the purchase price up to a point where a purchase is no longer economical for Ontario Hydro.

As the final price would be determined by these market forces, it is difficult to assign a reliable standard cost to the purchase option. However, without considering what effects competition would have on price, we have enough data to suggest that the standard cost of a large purchase from Manitoba or Quebec would be in the area of $40/MW.h - $45/MW.h. or more. Competition from American utilities could drive up the price another $5 to 10/MW.h. The price is also sensitive to changes in the discount rate and capital costs. Since hydraulic plants are capital-intensive options, this sensitivity is expected.

Two recent purchase transactions have been announced, subsequent to the evaluation of purchase options discussed above. To provide a comparison, standard costs are estimated for these transactions. First is the 200 MW purchase Ontario Hydro has contracted from Manitoba for five years beginning in 1998. It has a standard cost of $48 a megawatt-hour. Second is the letter of intent Hydro Quebec has signed with Central Maine Power Company. Central Maine may purchase up to 900 MW in 20 year blocks beginning between 1992 and 2000. The standard cost of this transaction for Ontario Hydro, assuming the same terms, would be about $69 a megawatt-hour. These two prices reflect the different market opportunities and suggest increasing purchase prices toward the upper end of the range and perhaps higher.

5.1 Important Questions About the Purchase Option

Does the purchase option offer Ontario Hydro greater flexibility?

With the uncertainty of growth in the demand for electricity, the flexibility afforded by an option is a vital concern. While it may be possible to arrange a purchase more quickly than to build our own facility, a number of conditions must exist. The selling province must have a surplus of generating capacity. Furthermore, transmission facilities must already be in place. Neither of these conditions is expected to exist. Manitoba and Quebec do not expect a capacity surplus in the 1990s nor do suitable transmission facilities exist for large scale purchases. To allow Manitoba or Quebec time to build new facilities, we may have to make a commitment in the near future; if we then change our plans, we will likely pay a penalty to reimburse the seller for his expenses.

What long-term benefits will accrue to Ontario Hydro?

The contracts under consideration run for a length of up to 15 to 30 years. In that period, we would likely pay a cost that is less than new coal plant, more than new nuclear plant and roughly equal to the cost of some of the better new hydraulic plants that could be built in Ontario. However, there is a significant point on which the purchase option differs from the rest: after the purchase contract has expired, the benefits of the plant revert to the selling province. And with a life span of 60 to 90 years, a hydraulic plant will continue to deliver power for many more years. Ontario Hydro will retain the transmission facilities built in this province, and although this is a valuable acquisition, it is obviously not as valuable as a generating station.

Will a purchase reduce Ontario Hydro's borrowing requirements?

When we build a major supply facility, we borrow money from various sources. The cost of borrowing is reflected in the cost of electricity. If the selling province can arrange financing for the construction of their facilities, our borrowing requirements will be reduced, but the cost of servicing the debt will be included in the cost to Ontario Hydro. However, it may actually be cheaper for Ontario Hydro to help finance the construction of facilities if we are able to borrow money at a lower cost than the selling province. The cost of borrowing will be reflected in the cost of purchasing electricity whether that cost is expressed in the purchase price or directly in the form of Ontario Hydro's interest expenses.

What impact will a purchase have on the provincial economy?

It will be good for the selling province, perhaps not so good for Ontario. Most of the money for a purchase is spent outside of the province and creates economic activity and jobs in Manitoba or Quebec. The lifetime employment percentages in Ontario of four major options were presented earlier in Figure 4.2. Only 14 percent of the jobs created as a result of a purchase will go to Ontarians. This could be offset to some extent if the

price Ontario pays for the purchase is less than the other available options. However, if the price is greater than other options available to Ontario, it could have a negative effect on the Ontario economy.

As the purchase uses a Canadian source of renewable energy, a purchase may reduce our dependence on foreign produced coal. Consequently, the Canadian balance of payments would not be adversely affected by a purchase but might be improved.

What environmental impact will a purchase have?

The environmental impact in Ontario of a purchase will be restricted to the effects of transmission line construction. The full impact of the construction and operation of a hydraulic plant will be felt in the selling province (see 4.2 <u>Hydraulic</u> for further details).

5.2 <u>Summary</u>

Further study is required to obtain a complete understanding of the costs and benefits of the purchase option. We need more information on: the expected costs incurred in the source province; the effect of competition on price; the extent of new transmission lines required in Ontario; and the peak capacity and energy requirements the purchase should be expected to fulfill. Some of these uncertainties should be resolved in the current negotiations.

6.0 OVERALL COMPARISON

6.1 Average Lifetime Energy Costs

The options being evaluated have quite different characteristics. Some can only operate for short periods while others can operate all year long. Some can be started up and operated when they are needed while others operate only when the sun shines or the wind blows, regardless of whether or not the energy is needed at that time. These and many other factors must be considered when evaluating the average cost of the energy produced by each option over its lifetime.

At present, we are able to identify a range of lifetime energy costs associated with each of the options (see Figure 6.1). These costs have been calculated according to the 'standard' cost methodology described in Appendix A. In some cases, such as nuclear and coal, the technology is well defined and so the range of costs is fairly small. In other cases, such as small hydraulic and cogeneration, the costs may be site specific or depend on whether or not waste fuel is available; thus the range of costs is much wider. The economies of scale resulting from building more than one generating unit at one site (ie, multi-unit stations) are illustrated for the nuclear and coal options. The higher costs of single unit stations make them unlikely options and so their costs have been shown separately.

The demand options, load shifting and conservation, actually represent a large number of specific activities to help our customers change the pattern or efficiency of their electricity use. Therefore, desirable demand programs will include a number of options ranging from those that are lower in cost than supply alternatives up to those that are comparable in cost.

6.2 Potential Contribution to Power Requirements

In terms of planning for the future, cost is only one consideration. It is also important to know how much of an option (MW) can be acquired by the time we may need it. Figure 6.2 compares the potential contribution that each option could make to satisfying the growth in the system's peak demand by the year 2000. The potential is divided into that which is reasonably assured and that which is less certain.

The potential is generally limited either by how much is available at a competitive price or by how much can be built in the time available. The traditional supply options, such as nuclear, coal, oil and gas, fall into the latter category. Even if they were the preferred option, the 10 to 15 years that is required to gain approval and then design and construct them, limits the amount that could be built by the year 2000.

Figure 6.1
AVERAGE LIFETIME ENERGY COST

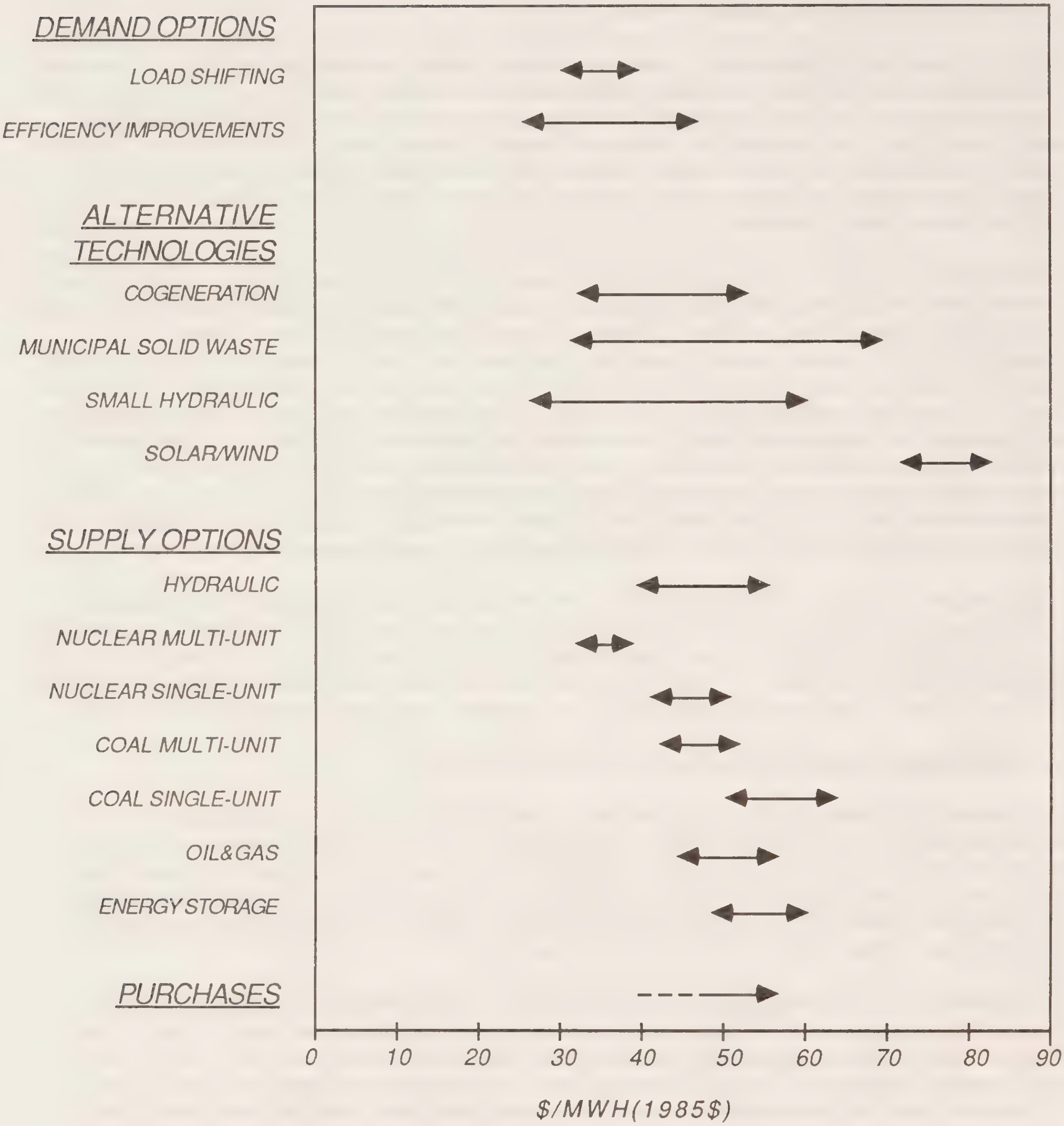
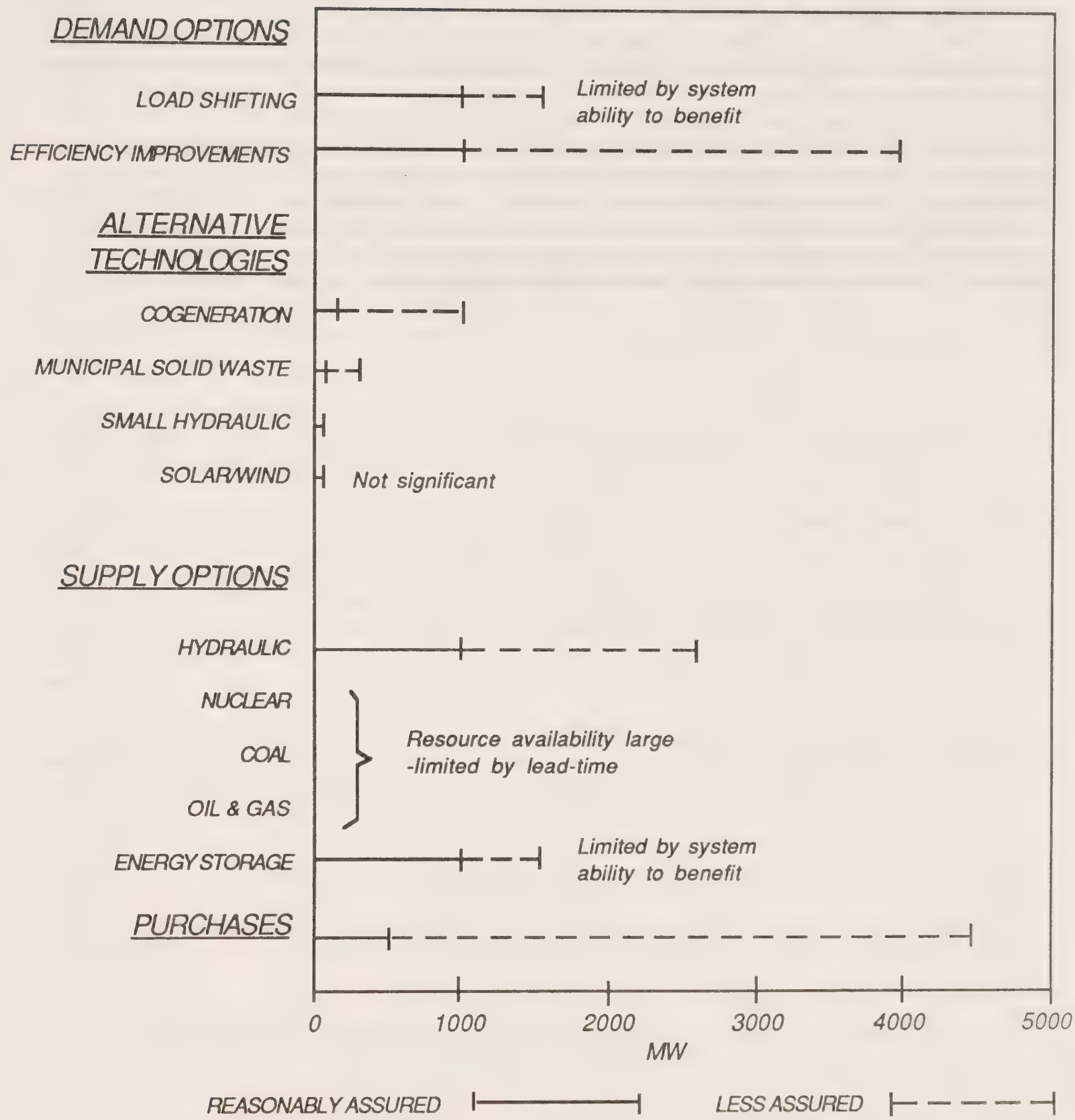


Figure 6.2
POTENTIAL CONTRIBUTION TO POWER REQUIREMENTS BY THE YEAR 2000



Hydraulic as well as alternative technologies, such as cogeneration and municipal solid waste, have shorter lead-times but are limited by the number of sites that are economic. Demand reduction is similar in that it depends not only on how many efficiency improvements can be made, but also on what level of incentive can be justified and how receptive the customers will be to Ontario Hydro programs.

The potential for purchases is based on the range of 500 to 4500 MW under consideration.

Load shifting and energy storage options are limited by how much the peak demand for electricity can be shifted before a new peak occurs in what was originally the off-peak period of the day. Our estimate is that 1000 to 1500 MW of load shifting may be desirable in the year 2000. Since load shifting and central energy storage options satisfy the same need, it appears that the lower cost demand-side options may be more desirable.

7.0 RELATIVE ECONOMIC IMPACT

As part of the Phase I activities, Ontario Hydro investigated(i) the effects on the Provincial economy of implementing selected demand and supply options for meeting future electricity needs in Ontario. These options include load shifting, efficiency improvements, nuclear- and fossil-fuelled supply, peaking hydraulic generation, cogeneration and purchases. The options are evaluated for their effects on Ontario's real Gross Provincial Product (GPP) and employment. The economic effects considered include those of the construction and operation activities and effects on the electricity user through price.

Each demand and supply option has been standardized to meet a typical 68% load factor increment to system needs. Where the load factor of an option differs from 68%, the additional energy supplied or displaced in the system is considered in the economic evaluation. The life-cycle construction, operation, fuelling and energy price impacts on Ontario's GPP and employment have been estimated with the help of a Canadian regional input-output economic model.

Figure 7.1 illustrates the relative impacts of the options being considered. The areas of the circles denote the impact on GPP relative to high cost purchases. Larger circles denote more desirable options.

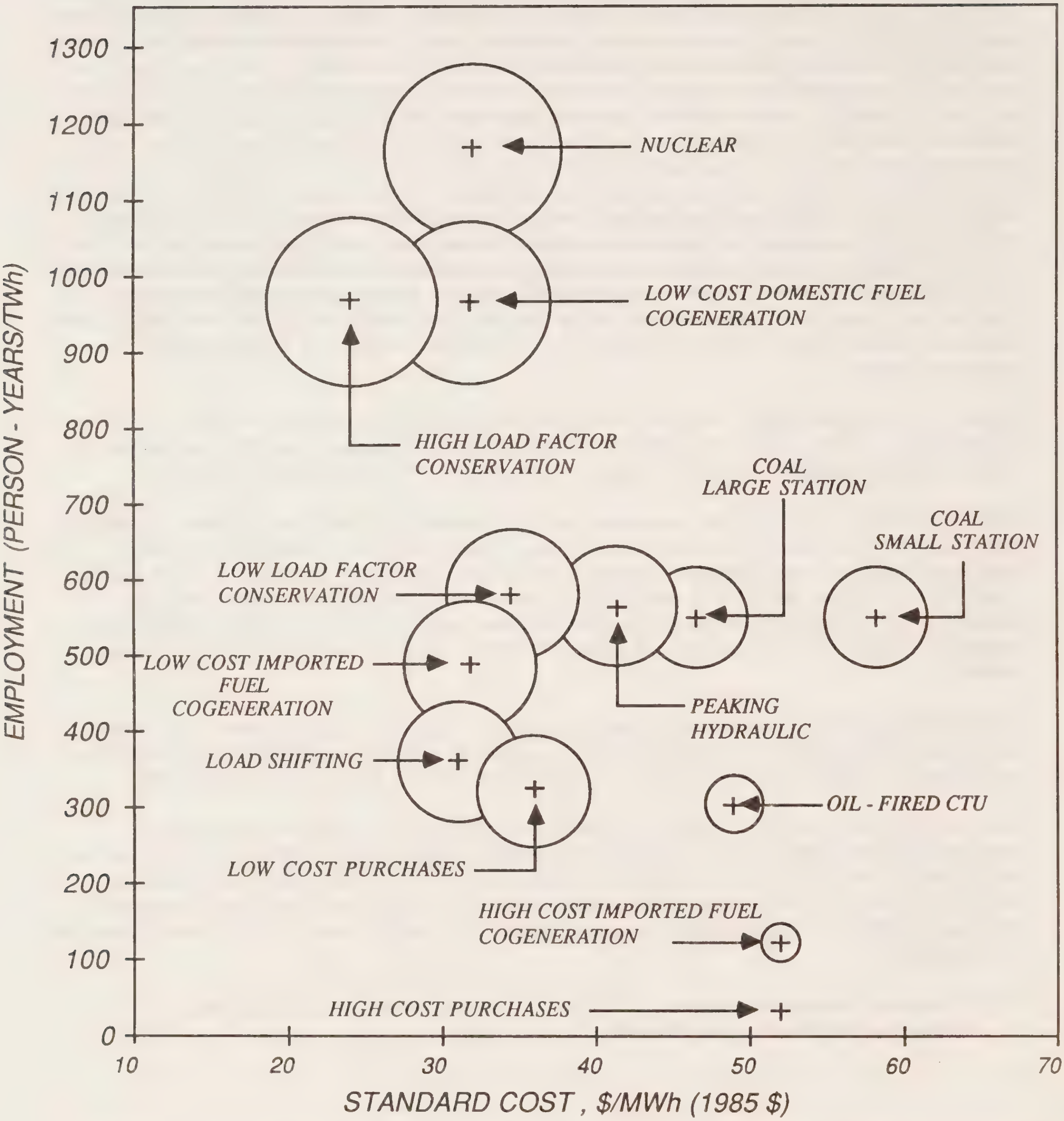
The options providing the greatest economy-wide GPP and employment benefits are found to be nuclear generation, high load factor conservation and low-cost indigenous-fuelled cogeneration such as that generated from waste products. These options combine low costs with relatively high Ontario activity in installation and/or operations and fuelling. Their high load factors minimize the use of imported fossil fuel to make up system energy needs.

The options with the lowest impacts are the high-cost purchases and the high-cost imported fuel cogeneration options. These options also involve relatively little direct domestic construction or operations activity.

One can compare these results to the employment information presented previously in Figure 4.2, and in particular, the total effect on Provincial employment versus the job creation associated with construction activity. It can be seen that lower load factor options, such as Ontario's remaining peaking hydraulic resources, appear less favourable under this more detailed evaluation.

(i) "Ontario Economic Impact of Hydro's Demand and Supply Options", Economics & Forecasts Division, May 1986.

Figure 7.1
RELATIVE ECONOMIC IMPACT



Areas of circles denote the impact on GPP (per MWh) relative to high cost purchases. Larger circles denote more desirable options.

APPENDIX A

'Standard' Costing

The objective of Meeting Future Energy Needs is to determine the best methods of meeting increases in electricity demand in the mid to late 1990s and beyond. One of the prime determinants of what is 'best' is the lowest cost. However, the variety of options being considered is very large and many options do different 'jobs'. For example, a pumped storage plant which stores energy from under-utilized coal-fuelled plants at night to meet peak daytime electricity demands is doing a different job than a nuclear plant which produces energy in both peak and off-peak times. Furthermore, a wind generator - which can generate electricity only when the wind is blowing and will not necessarily be available at peak times - does a different job than increased insulation in a house which will save energy in the winter, particularly on cold days of peak demand. To produce a fair comparison, it is necessary to standardize the 'job' that has to be performed and adjust the costs of all the options so that they perform the same job.

The Standard 'Job' is to Supply an Increase in Normal Load at 68% Load Factor

The Meeting Future Energy Needs study is looking at ways of meeting increases in electricity demand, both in peak power and in energy which are beyond the capability of the base system (ie, the existing system together with the generation stations that are at present under construction). The standard 'job' is to supply customers with an increase in demand of normal 68 percent load factor load (the average increase in load over the year is 68 percent of the increase on the peak day). With this increase the demand is greater than the capability of the base system. Since the natural characteristics of the options do not necessarily match the 'standardized job', the operation of the base system must be adjusted. The base system has flexibility because it is only fully utilized at peak times. The amount of energy produced at off-peak times can be adjusted to make up an option's deficiency in energy production provided the option can be used to meet the increased peak requirement.

Transmission and Distribution Costs are Included

Another difference between options is that some options, such as large nuclear and coal stations, deliver electricity in large quantities to the high voltage bulk transmission system, while other options, like cogeneration or efficiency improvements, either produce or save electricity in smaller quantities closer to the ultimate customers. These options tend to have lower requirements for additional transmission and distribution. The standard costs account for the costs of losses associated with transmission and distribution.

The Standard Cost Includes the Costs to all Participants

In setting up a costing methodology, it is necessary to decide from what perspective costs are to be calculated. This is particularly necessary for demand options and alternative generation options where several parties are likely to be involved. The perspective chosen for the 'standard cost' is that of society at large, or in other words, all the participants together. For a demand option the cost of additional insulation for example is included even though it may be paid in whole or in part by the customer; for a cogeneration plant, the additional costs of generating electricity with steam production is included although the owner of the cogeneration plant may pay these costs. However, rate incentives, lost revenue due to efficiency improvements, and payments to cogenerators to purchase their power are not included since these are merely transfers of money among the participants and not actual costs. This perspective, which is sometimes called 'least cost energy analysis', is useful for an initial screening and ranking process because it calculates benefits in total; if there are no net benefits to society, then an option should be discarded. Later stages of analysis have to determine whether rates and incentives can be devised that will be acceptable to all participants so that an option can proceed.

The Standard Cost is Quoted in Dollars Per Megawatt Hour

The standard cost is quoted as an average annual cost of using the option to supply an increase of one unit of annual energy demand. This standard cost is expressed in dollars per megawatt hour. For example, a 1 kilowatt electric heater may be used 1000 hours per year using electricity that costs 5¢/kW.h. In the year, it will use 1000 kilowatt hours or 1 megawatt hour, and the cost would be $50. Therefore, 5¢/kW.h is equivalent to $50/MW.h. Quoting the costs per unit of energy allows a comparison of the costs of options with different inherent sizes.

All costs are quoted at 1984 general price levels, so that the costs will be comparable to the costs we are currently experiencing. However, since the options are being considered for use in the mid to late 1990s and beyond, we have to forecast future costs. An adjustment is made if the cost of any component is expected to increase faster or slower than prices in general. For instance, because of increased concern about the effects of acid gas emissions and the effect of current and possible future regulations in both Canada and the U.S., it is expected that the cost of high sulphur coal will fall relative to the cost of low sulphur coal.

Capital Costs are Converted to Annual Costs Using a 4% Real Discount Rate

Since 'standard' costs are based on average annual costs, it is necessary to convert the initial capital costs into average annual costs. This conversion requires assumptions about the effective cost of money and the useful life of the option. The useful life is estimated for each option;

the effective cost of money is the same for all options. The best indication of the effective cost of money over the life of an option is the 'real' discount rate. This is the expected cost of money based on nominal interest rates less the inflation rate. For example, if interest rates are about 10 percent and the inflation rate is about 6 percent, then the 'real' discount rate is about 4 percent. Removing the inflationary component from interest rates eliminates the part of the interest that compensates for the general loss in value of money and leaves the component that represents a real increase in the purchasing power of the loan repayments. The standard costs are quoted based on a 4 percent real discount rate which is the Ontario Hydro estimate of the average long-term value. This is a little lower than would be estimated based on current inflation and interest rates, but is considerably higher than would have been estimated in the 1970s. Sensitivity analysis tests the effect of a 6 percent real discount rate on standard costs.

Estimating the Contribution to Reliably Supplying Peak Loads

One of the first steps in calculating the standard cost is to estimate the size of the load increment that the option can supply. Since the option is to be relied upon to meet the peak power requirements of the increase in load, an estimate must be made of the probable contribution of the option at peak times. For a coal, oil, or nuclear plant this is the installed capacity less an allowance for the probability that the unit will be out of service for repair. Even though a peaking hydraulic plant may operate at a low capacity factor, the water can be stored behind the dam and used only at peak times. A peaking hydraulic plant may therefore make a contribution at peak times close to its maximum capacity. Wind and solar however cannot be controlled and make relatively small contributions to reliably meeting peak loads.

For demand options, one of the largest factors is the probability that the energy using devices that are controlled or conserved are in use at peak times. If more efficient devices are used, they will not all be in use and saving energy at peak times. For load shifting options and energy storage options, an additional complicating factor is that they can only contribute to meeting peak demands if sufficient under-utilized energy production capability exists at off-peak times to provide the basic energy supply. Having calculated the contribution at peak times and estimated the size of the load increment, it is then possible to calculate the associated increase in energy demand assuming the 68 percent load factor of typical load. Once the increase in energy demand has been determined, the fuel costs can be calculated.

The Standard Cost Includes Fuel Costs

The fuel costs associated with an option are of two types. Each option may have a fuel cost associated with its own operation. In addition, as indicated earlier, the operation of the base system is adjusted to match the energy production of the option to the 68% load factor normal load.

Therefore, there will also be changes in the fuel cost of operating the base system. For example, peaking hydraulic cannot produce enough energy; it is necessary to produce extra energy from the base system. In the case of oil fuelled combustion turbines and some other options, the cost of operating the option is higher than the cost of generating extra energy from the base system except during peak periods. In these cases the energy is produced from the base system when it is more economic to do so and thus tends to reduce the standard costs of these options.

The Standard Cost Includes Costs of Mitigating Potential Environmental Impacts

The standard cost includes the costs of making each option environmentally acceptable. For nuclear options, this includes allowances for long term disposal of spent fuel and for the ultimate decommissioning of the nuclear station. For coal fuelled plants, the capital and operating costs of acid gas emission controls are included. For those options that require additional energy from the base system, an allowance is made for the cost of control measures at existing plants. Each option must have sufficient acid gas controls to ensure that there is no increase in acid gas emissions associated with the adoption of that option.

The Standard Cost Includes an Allowance for Export Profits

Ontario Hydro has never built generating plant for the export of electricity. Nevertheless, generating plant that is built to meet Ontario's need may create profits when we export electricity during non-peak periods. This effect is included in the standard cost.

The Standard Cost Includes Operation, Maintenance and Administration Costs

The costs of operation, maintenance and administration are included in the standard cost of each option. For a major supply option such as coal or nuclear it includes the cost of the staff and materials to operate the plant. For demand options it would include any other annual costs payable by the customer, the municipal utility or Ontario Hydro that have not been included as fuel costs.

It is Also Necessary to Check the Sensitivity of the Standard Cost to Changes

A standard cost analysis based on the most probable conditions only reveals part of the story. The factors used to make the estimates of future conditions are themselves subject to uncertainty. Therefore, it is important to know how the standard cost would vary if actual conditions turn out to be different from the most probable estimates.

The Standard Base System

As indicated above, the standard cost calculation assumes various base system characteristics. We assume a standard base of the existing system plus any plants under construction and any existing demand side options; however, over the life of the option the character of the system will be gradually evolving as new plants or programs are added to replace retiring plants and meet load growth.

For the standard base system, it is estimated that if additional energy production is required, then the energy would be produced from coal 75 percent of the time. However, during some peak hours (5% of time) it would be necessary to produce energy from some form of oil-fuelled plant because all the hydraulic, nuclear and coal-fuelled plants would be fully utilized. Furthermore, during some low load periods, mostly during nights and weekends, (20% of time) additional nuclear energy could be produced because the load would be less than the capacity of the hydraulic and nuclear plants.

A High Capital, Low Operating Cost Base System

The nature of the base system will gradually change if it is developed using only high capital cost, low operating cost plant such as nuclear or high capacity factor hydraulic purchases.

A test was done on how the standard cost would change if a high capital cost base system were assumed. This is how the system would be in about 2010 if only high capital cost plant were added. In this case, the proportion of time additional nuclear energy would be available would rise from 20% to 40%; oil would supply additional energy during peak hours 5% of the year; and the hours when additional energy would come from coal would fall to 55% of time. With the high capital cost base system, the standard costs tend to rise for additional plants that have high capital cost and low energy cost because the system already has a large component of such plant and there is less need for additional low cost energy supplies.

A Low Capital, High Operating Cost Base System

Standard costs were also calculated for a low capital cost, high operating cost base system. This is how the system might look by the year 2010 if only coal and combustion turbine plant were added to the system. In this case it is estimated that the proportion of time when additional energy would come from oil-fuelled plant would rise from 5% to 20%, and in all remaining hours (80% of time) additional energy would come from coal. There would be no under-utilized nuclear capability. In this case, the standard cost rises for additional plant that does not produce cheap energy because the system has an excess of higher operating cost plant. Conversely the standard cost tends to fall for plants that do produce large quantities of low cost energy.

Additional Sensitivity Tests

In addition to varying the system characteristics, other sensitivity tests were performed. Capital costs were varied from 20% above to 20% below the base estimates for established technologies and by plus or minus 30% for new technologies. Availabilities were raised from 10% above to 10% below the base estimate for new technologies. Useful life was varied by plus or minus 25% of the base estimate for new technologies.

The sensitivity tests were more severe for new technologies, such as integrated coal gasification, than for existing technologies because there is a greater measure of uncertainty in these cases where we have no experience building or operating commercial size plant.

As mentioned previously, we tested the effect of "real" interest rates remaining high by also using a 6% rate.

Fuel costs can vary substantially and are often determined by international market forces. Oil and gas prices are expected to remain stable in real terms for the remainder of the 1980s and then to rise in the 1990s as more expensive sources have to be brought into production. By the turn of the century, oil and gas prices will be 35% higher relative to the prices of other commodities. A sensitivity analysis tested the effect of a smaller rise in oil and gas prices, equal to the increase in other prices. A test was performed to see the effect of a 25% increase or decrease in the price of uranium.

Since any new generation and demand management options are developed primarily to meet the needs of Ontario, we tested the effect on the standard cost of eliminating all export profits attributed to the option. This test gives the standard cost of meeting only Ontario's needs without any influence from the possibility of increasing export profits.

Standard Costs are Only Part of the Full Economic and Financial Picture

The standard cost is a simplified way of comparing diverse options on a common basis. It is a useful tool for an initial look at demand and supply options so that a general assessment can be made of relative long term economics and ranking from a cost point of view. There are many planning, economic and financial factors that must be addressed before specific recommendations can be made about a preferred system plan with a selected mix of options. These additional factors that must be studied include:

- the amount of each option. Standard costs have been calculated for a unit increment in each option. Many options are subject to the laws of diminishing returns - the more you have of an option, the less advantageous it is to have more of that option. For example, a system may find a few combustion turbines advantageous for occasional peaking use. However, a system with too many combustion turbines will use them often and experience very high fuel costs.

- the interactions between options. Each option is evaluated separately as the next addition to the system. Some combinations of options work very well together, while other combinations of options do not. For example energy storage supply options and load shifting demand options both do the same job; they both utilize unused energy production capability at night to supply daytime loads. The more of one of these options that is implemented, the less you need of the other.

- the timing and order of implementation. The standard cost does not address specific in-service dates and which options should be developed first.

- the year by year effect on electricity rates. The real discount rate of 4% is a good measure for determining the average cost over an option's lifetime. However, it is expected that inflation will continue and that accounting costs based on actual interest rates, including the component due to inflationary expectations, will be higher than the standard cost in early years and lower in later years. This is particularly relevant for options where most of the cost is the initial capital expense, eg, hydraulic, nuclear and many energy efficiency options.

- the year by year effect on borrowings and debt. Financial factors are not addressed. Depending on the developing financial situation and on other corporate plans, there may be years where increased capital spending will not be restricted except by normal limitations on borrowings and debt; there may be years when capital spending is more difficult.

- the value of flexibility. The standard cost does not assign a value to shorter lead time or lower capital intensity. These are factors which may make it less expensive to change plans to accommodate changing demand forecasts.

- the incentives required to implement demand options. Many demand and small generation options will require rate incentives, low interest loans, equity participation, changes in regulations, etc, for the utilities to encourage customers to implement them. As indicated previously, the standard cost is calculated from the combined perspective of all parties and does not consider the appropriate levels of incentives.

Further System Studies are Underway
<u>to Evaluate Some of These Issues</u>

Most of these issues require very complex studies of the effects of complete programs. System costs must be evaluated on a year-by-year basis and included in a detailed forecast of rates, debt levels, etc. In addition, to evaluate flexibility issues, it is necessary to consider the effects of actual loads different from forecast loads and the costs that would be involved in modifying plans in "mid-stream". These studies are underway and will add further information that will be useful in selecting a preferred combination of options.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT C

DEMAND MANAGEMENT

December 1987

Market Services and Development Division

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DEMAND MANAGEMENT OPTIONS

CONTENTS

TABLES

DEMAND MANAGEMENT OPTIONS

1.0 INTRODUCTION

When it comes to planning for customer electricity needs in the 1990s and beyond, the public is generally familiar with traditional supply side options, such as building more hydro-electric, coal-fired, or nuclear generating stations. But there is less public awareness about demand management options. The purpose of this document is to help increase awareness of the many demand management options that are available and should be considered as we plan our electricity future.

In this brief report, it is not possible to describe all potential programs or to evaluate which is the most appropriate. In particular, an electricity user with numerous inter-related uses of electricity and complicated production processes is apt to qualify under a number of potential programs. To be done effectively, demand management options will have to be tuned to each industry and segment of the market, which cannot be reflected in a general report.

Section 1.1 has two tables. The first one lists examples of Ontario Hydro´s publications which provide information on energy efficiency. The second table lists a variety of demand management options relevant to Ontario circumstances.

The report has two sections in addition to the introduction. Section II covers Load Shifting, including rate-related measures and direct load control. Section III covers electrical Efficiency Improvements.

1.1 Examples of Demand Management Options

Demand management begins with the customer/Hydro interface. Probably the most familiar demand side option to Ontarians is the provision of energy efficient information. Table 1 indicates a list of pamphlets and brochures available from Ontario Hydro on ways to use energy more efficiently. In addition to the brochures is the two-volume Commercial Energy Manual, which is a reference guide for contractors and design engineers.

Table 2 outlines some of the demand management technologies applicable to Ontario circumstances. The technologies are listed in a generic way rather than as specific products. To the extent possible, the technologies are listed under the market sector where they are most important. The list is not intended to be comprehensive.

TABLE 1
PAMPHLETS AND BROCHURES ON ENERGY EFFICIENCY

Residential:

- Using Electricity Wisely
- Efficiency Plus; A Consumer´s Guide to Home Systems and Appliance Maintenance
- Energy Efficient Home Guidelines
- Wise Ideas For Efficient Summer Cooling
- Heat Pumps Beat The Others Cold
- Getting a Home Heating/Cooling Analysis
- EnerMark Loan Plan
- Electricity and how you use it
- Electric Heating Options For Your Home

Agricultural:

- Electric Radiant Brooding
- Electricity in Agriculture
- Energy Management on the Farm

Commercial:

- Using Electricity Wisely In Condominiums and Apartments
- Energy Efficiency For Hotels and Motels
- Cut Cost, Increase Comfort With Internal Source Loop Heat Pumps Systems
- Electric Options (23 issues to date, 13 featuring heat pumps)
- In-Suite Electric Heating For Condominiums and Apartments
- Condominiums and Apartments With In-Suite Electric Heating
- Condominiums and Apartments With In-Suite Electric Water Heating
- In-Suite Electric Water Heating For Condominiums and Apartments
- Guest Room Comfort For Hotels and Motels
- Rates and Billing Summary

Industrial:

- Power Factor
- Rates and Billing
- Induction Heating

TABLE 2
DEMAND MANAGEMENT TECHNOLOGIES

RESIDENTIAL

Heating and Cooling

Cold Climate Heat Pump
Ground/Water Source Heat Pump
Bivalent Heat Pump
Variable Speed Heat Pump
Multi-Evaporator Heat Pump
High Efficiency Air Conditioners (Central and Room)

Building Envelope

Insulation (Basement, Wall, Ceiling)
Caulking (Sealing)
Window Units (Multiple Glazing, Air Spaces)
Controlled Ventilation (including heat recovery)
Passive Solar Design

Appliances

Refrigerators
Microwave Cooking
Convection Ovens
Freezers
Heat Pump Dryers
High Efficiency Motors (fractional horsepower)

Water Heating

Heat Pump Water Heater
Desuperheater (add-on to heat pump)

Lighting

Compact Fluorescents
Improved Lighting Design

Load Shifting

Direct Load Control (Water Heat, Air Conditioning)
Timers (Water Heater, Pool Pump)
Thermal Energy Storage
Programmable Controllers/Appliance Interlocks

TABLE 2 (continued)

AGRICULTURE

Heat Exchangers (Ventilation)
High Efficiency Motors
Ground/Water Source Heat Pumps (heating and cooling for greenhouses, mushrooms, etc)
High Efficiency Lighting (greenhouses, security)
Heat Recovery (eg, Milk Cooling to Water Heating)
Insulation

COMMERCIAL/INDUSTRIAL

Motors and Equipment

High Efficiency Motors
Variable Speed Drives
Higher Efficiency in Mechanical Equipment (pumps, compressors, chillers, etc)
Optimum Motor Sizing

Heating/Ventilation

Heat Pumps (including water loop internal source, ground source)
Variable Air Volume Systems
Exhaust Air Heat Recovery
Ventilation to Suit Building Design and Use
Economizers
Destratification Fans
Heat Recovery Absorption Chillers
District Heating

Heating

High Efficiency Fixtures (eg, High Efficiency Fluorescents)
High Efficiency Ballasts
Substitution to More Efficient Lighting Types (eg, high pressure sodium for mercury vapour)
Photocells
Daylight Dimmers
Motion Detectors
Delamp/Wattage Reducers

TABLE 2 (continued)

Building Design and Envelope

Insulation (roof, wall)
Optimized Window Design
Multiple Glazing
Solar Film/Low Emissivity Glass
Optimized Entrance Buffer Zones
Double Envelope
Building Mass/Trombe Walls
Design for Daylighting Technologies
Curtains/Shutters
Exterior Shading
Weatherization/Infiltration

Refrigeration

Insulation (pipes, tanks)
Condenser Heat Recovery
Variable Size Compressor Banks
Automatic Defrost Controls
Glass/Acrylic Doors

Process Changes

Heat Pumps (eg, pre-heating from cooling water)
Conveyor Substituted for Blower
Mine Electrification (drilling, ventilation)
Induction Heating of Metals (vs resistance heating)
Microwave Drying (vs resistance drying)

Water Heating

Heat Pumps
Lower Temperature Storage
Point-of-Use vs Control Heating
Insulation

Load Shifting

Thermal Energy Storage (heat and cool)
Scheduling of Industrial Processes
Interruptible Power
Energy Management Systems
Programmable Thermostats
Timers

Miscellaneous

Cogeneration
Capacitors

2.0 LOAD SHIFTING

Demand side options can generally be placed in two major categories: Load Shifting and Efficiency Improvements. This section describes in further detail some of the issues and activities associated with the Load Shifting. The following section does the same for Efficiency Improvements.

2.1 Time-of-Use Rates

It can be expected that electricity users will shift some of their load if their cost is different depending on the time of day or day of the week, similar to the response to long-distance telephone rates. The main objective of time-of-use rates is to encourage customers to shift their electricity use from peak to off-peak times. The topic is somewhat complicated in Ontario by the fact that most customers are served not by Ontario Hydro but by municipal utilities which buy power at a so-called "bulk" rate from Ontario Hydro. A significant shift in municipal loads will depend upon how the utilities pass the time-varying cost of bulk power through to the retail level, ie, mandatory or voluntary, available to some customers or all, a large time-differential or small, scope of helpful information to the customer, etc.

The current situation is that Hydro plans to introduce a time-of-use bulk rate in 1989. Some very large electricity users can be expected to shift some loads toward night work-shifts. Some of these large users are direct customers of Ontario Hydro while others are municipal utility customers. The illustrative rates vary by time-of-day, in a ratio of approximately 1.4:1, plus the demand rate which applies primarily during peak hours. The illustrative rates also vary between winter and summer, the winter rates being approximately 1.4 times higher than corresponding summer rates.

Municipal utilities will have the options of paying bulk time-of-use rates, and in turn may introduce time-of-use rates on a broader basis, ie, to the majority of customers whose individual usage is comparatively small. Implementation of time-of-day pricing can be expected to shift the load, judging from the results of experiments and experience in other jurisdictions. Introduction across the board would require modified or new meters for approximately 3.2 million customers. However, introduction on a partial and/or voluntary basis

would decrease this number, with a corresponding decrease in the amount of load shifted. Introduction of a seasonal rate (without the time-of-day feature) could be accomplished without a major change in metering. The existence of higher time-of-day winter rates may result in larger quantities of load being shifted during the winter, as well as inducing greater efficiency in winter-time loads.

Ontario Hydro and the municipal utilities have conducted experiments with a variety of time-of-use rates since the early 1980s. The objectives have been to determine customer acceptance and to estimate the amount of load that would actually be shifted. Hydro also stays abreast of developments in time-of-use metering, which is improving with electronic technology. The residential experiment is nearing completion, while the general service class experiment will continue until the early 1990s.

The information from the experiments to date indicates that most customers view time-of-use rates favourably and that there can be significant shifts in consumption patterns if cost savings are attractive to customers. It is inevitable, however, that there will be a lot of uncertainty about the extent of load that will be shifted; for example, there may be innovations in appliances to make timers more easily used, but these will only happen if there is a permanent and widely available time-of-use rate.

2.2 Interruptible Rates

The interruptible rate is an option available to large customers, under which they get a lower electricity rate in return for a commitment to cut their load to a predetermined level when notified by Ontario Hydro. This allows Hydro to reduce the amount of peak capacity it needs to build and, ultimately, reduces costs to all customers. Interruptible rates are considered a load shifting option because, it is assumed, the customer catches up on his requirement at a later time when power is available. Hydro currently has over 1,000 MW of interruptible power contracts, of which about 600 MW is expected to be in use at a given time and therefore available for shifting. While this is substantial among North American utilities, there may still be potential for additional interruptible options.

A higher or lower discount could be justified by greater or lesser commitments from the customer

concerning items such as the frequency and duration of curtailment, the amount of notice time that must be given, and so on. It is possible to imagine interruptible features being introduced to a larger number of smaller customers, for example, as a result of communication system improvements. At present, notification is directly by telephone.

Interruptible power requires the cooperation of the participating customer. If participants choose to discontinue their agreements, a period of adjustment may be needed. This would depend upon the size of service and the number of participants opting out.

2.3 Thermal Energy Storage

Thermal energy storage systems can be designed to store either coolness or heat for space conditioning. For coolness, the system stores ice or chilled water. The freezing or chilling process would use electricity during the off-peak period. The subsequent cooling of the building during the peak period requires a small amount of electricity for fans or pumps to distribute the cool air. For heat, a medium such as crushed rock in an insulated enclosure is heated by electric elements during the off-peak period, and the heat is released to the circulating air during the peak period. These technologies are most highly developed for commercial buildings, but storage heating for houses is also available.

The most common form of thermal energy storage is hot water for domestic use. This topic is addressed in Section 2.4, with reference to direct control of water heaters.

Energy storage systems allow for load shifting where the alternative is a conventional cooling or resistance heating system. If the alternative is non-electric, for example gas-fired heating, then promotion of storage heating has the effect of adding load in off-peak periods and neither increasing nor decreasing in peak periods. Energy storage is amenable to direct load control, and thus improves the load factor.

Thermal energy storage could be encouraged by developing and distributing information about the various systems, including the sizing requirements and economics in an Ontario context. Information should be made available to developers and architects very early in the planning process for their major

projects, and perhaps customized to individual projects. This method would facilitate space allocations for the storage, which can be on each floor and thereby decrease the size of ducts and air handling equipment. Another type of program would be financial assistance toward the higher capital cost of the storage system. The level of incentive would depend on the value of load shifting to the system´s capacity requirements, and also on the level of incentive given indirectly by time-of-use and demand rates.

2.4 Direct Load Control

Direct load control refers to a system by which the electric utility can remotely control specified loads in the customer´s premises by remote control. Control systems can involve pilot wires, radio signals, or signals superimposed on the electric distribution system. Generally speaking, the customer is charged a lower rate by the utility and the user is unaware of the current being switched off. For example, a number of municipal utilities now control some of the residential electric water heaters in their areas for relatively brief periods of a few hours. In such cases, a large number of units are controlled simultaneously. An issue associated with this practice is that at the end of the control period there will be a period of higher than normal load as all of the units "catch up" together.

Marketing programs for direct load control tend to focus on water heating in houses or multi-unit residential buildings. One necessary aspect of a program is information to the customer about load control, including the requirements for a larger hot water tank. In general, the longer the control period, the larger the water heater has to be to ensure an adequate supply of water. Since Hydro´s load shape necessitates shifting for approximately 16 hours on some weekdays, research has been conducted on the size requirement for various households and on the availability of suitable heaters. Another necessary aspect of a program is the design of an incentive package to compensate for the cost and space for the larger tank, and the higher probability (at least perceived) of running out of hot water. The incentive can be a rate discount, a rental arrangement, and/or a flat rate.

Ontario Hydro has been a leader in research on direct load control of water heaters, and this effort is ongoing. There has also been research on control of other loads, particularly storage space heating.

3.0 EFFICIENCY IMPROVEMENTS

3.1 Heat Pumps for Residential Space Heating

Space heating is the largest use of electricity in many homes. There are several types of heat pumps which offer significant electric conservation potential using central air conditioning and resistance electric space heating as the reference point. There have been improvements developed that will enable it to extract more heat from fairly cold air. However, air-to-air heat pumps have the disadvantage (from the electric utility viewpoint) that they offer no efficiency gain when it is needed most, at the time of the system peak during very cold weather.

There are two types of heat pumps which can overcome this disadvantage: ground/water source heat pumps and bivalent heat pumps. The former draw heat either from ground water (open loop) or from a liquid medium which is warmed as it passes through an underground piping system (closed loop). They also provide highly efficient air conditioning. The bivalent heat pump draws heat from the outside air when it is warm enough, and otherwise is supplemented by a gas flame in an outdoor enclosure. Both types are more expensive than standard heat pumps, and considerably more so than simple resistance heating systems.

Ontario Hydro's current activities to encourage more efficient space heating include cooperative advertising, favourable financing to purchasers, and distribution of information about products and performance. Possible future initiatives include even better financing or capital rebates for ground source and bivalent heat pumps, based on the saving in system peak capacity. Detailed load monitoring of ground source heat pumps is under way in a number of locations in both northern and southern Ontario, most notably the Bayview Hill development in Richmond Hill, to verify the extent of efficiency gains and to develop information to distribute. The same is true for bivalent heat pumps. Hydro is currently testing customers' response to incentives in some locations, and is doing research with the manufacturers to improve product performance.

3.2 Efficiency Improvements in New Housing

Apart from heat pumps, there are two main ways in which new houses can use less electricity for space heating than the current norm. One way is an improved thermal envelope: more insulation, a better air barrier, windows located strategically and with higher R-value. The other main way is recovery of heat from vented air and used hot water.

Current marketing programs to encourage efficiency improvements in new housing rely mainly on personal contact and distributing information to builders, developers, and prospective buyers. Participation in projects such as model homes is another method of publicizing them. The R2000 home has been promoted by all of these methods. Monitoring of homes after they are occupied serves to verify that the innovations do work as hoped, with respect to their electrical consumption. It is also necessary to be aware of the quality of the indoor air.

Potential future programs in this area include financing of the added cost of the upgraded envelope and equipment consistent with Hydro's "savings" in peak capacity. A "label" for the house can serve to assure the first-time buyer and subsequent resale buyers that electricity-saving features have been used. A label might also serve to assure mortgage lenders that the applicant will have lower than normal energy costs to offset the incremental cost of efficient features.

3.3 Thermal Envelope of Existing Houses

Houses with original equipment electric heating have been generally built to a better efficiency standard than their contemporaries. Nevertheless, the older ones were built to a lower standard than at present, plus the effects of time and in some cases neglect suggest that cost effective improvements could be made to decrease the electricity used for space heating. Furthermore, there have been many full or partial conversions to electric heating, especially from oil heating, in houses which were not built to the electric heating standards in the first place. The changes that can be made include insulation of attics, basements, and walls, and improved sealing and caulking. More expensive changes, such as new doors and windows, and even new exterior cladding, may not be cost effective, although they would save electricity in many cases.

The most usual utility activity is distribution of information. A more costly and effective approach is to offer free audits by trained personnel, who inspect the home, identify measures to be taken, and provide estimates of costs and savings. Audits have been offered by Hydro and many municipal utilities since 1981 under the name Residential Energy Audit Program (REAP), together with financing for conservation measures.

One possible extension of the audit approach is to develop a "label" showing the building´s expected heating requirement. If an extensive upgrade of the building were undertaken, its label could be changed to indicate this, which would increase the house´s value for resale and might enable the buyer to get a larger mortgage due to the lower expected fuel cost.

Another possible extension of the audit is to offer a full or partial rebate on any measures which are less costly than the corresponding cost of the power required if improvements are not made. The most notable example of this approach is the Hood River Conservation Project in Oregon. In this experimental program, nearly all the electrically-heated homes in the community were given thorough audits, and offers were made for full funding of the identified improvements. The homeowner´s acceptance of the measures and effectiveness of the installed measures in saving electricity were thoroughly monitored.

3.4 Household Appliances

There are a number of ways that major appliances could be manufactured to use less electricity. Refrigerators are mentioned most frequently in this context, including more insulation of sides and doors, more efficient motors and compressors. There are also ideas on how washers and dishwashers could be equally effective while using less hot water, which would save electricity in homes where water is heated electrically.

3.4.1 Approaches to Increasing Efficiency

Three approaches to increase the use of more efficient appliances are:

(i) extensive advertising/promotion, including energy consumption labelling;

(ii) mandatory energy efficiency standards for appliances; and

(iii) financial incentives.

(i) Advertising/Promotion

Advertising, promotions, and distributing pamphlets on energy efficient appliances increase consumer awareness for more efficient appliances. Another method of encouraging more efficient appliances is to label them as to their probable consumption. The Energuide label is an example of this approach. Research shows that many buyers do not pay much attention to such labels, even if they are quite prominent and are certified by an organization with high credibility. Also, the current labelling system has a weakness in that it does not translate energy savings into cost savings to the customer. Nevertheless, manufacturers have made efforts to get better labels on their products.

(ii) Mandatory Standards

Another approach is to have mandatory standards for the manufacturers and retailers of appliances. Manufacturers of 12 products in the U.S. requested and received government legislation which set energy efficient levels over the next three to six years. The manufacturers in Canada are, in the main, supportive of a similar approach. The Government of Ontario recently announced intentions of introducing an energy efficiency act (Throne Speech, November 1987). The act is to provide for higher standards of efficiency for appliances and heating and cooling equipment.

(iii) Financial Incentives

A third possible approach, which can be combined with either of the other two, is for the electric utility to offer a financial incentive to the buyer and/or the retailer. Experience with this approach in the U.S. suggests that, especially in the case of refrigerators

and window air conditions, the incentive should be made contingent on the consumer turning in the old appliance; otherwise, there is a tendency to use both the new efficient appliance and the old one, increasing load rather than decreasing it.

3.4.2 The Role of Ontario Hydro

Ontario Hydro is supportive of improving the energy efficiency of appliances. In 1965, Ontario Hydro initiated the introduction of standards for measuring the performance of electrical products with the Canadian Electrical Association (CEA). The CEA then requested the Canadian Standards Association to undertake the writing of such standards. Seventeen Standard Methods of Measuring Performance have been written, including those under the Energuide program.

There are a number of activities Ontario Hydro could carry out to support the introduction of more energy efficient appliances. These are:

(a) Advertising, promotional and educational activities aimed at encouraging the use of energy efficient appliances and raising the awareness and understanding of consumers regarding the energy consumption level of various appliances and the opportunities for them to reduce their energy use and costs.

(b) Providing technical support in the development of appropriate energy efficiency standards for appliances.

(c) Cooperating with the Municipal Electricity Utilities of Ontario, manufacturers, distributors and other parties to support the promotion of energy efficient appliances.

(d) Providing training as appropriate to encourage better understanding and support for the application of energy efficient products including the training of trades in application and installation standards.

3.5 High Efficiency Motors

A very high proportion of the electricity load consists of motors, most of them in commercial and industrial uses. The largest motors tend to be very efficient, incorporating the best materials and designs available. But the standard motor found in most equipment or stocked by motor distributors is less efficient than it could be. Most motors use about 3-5% more electricity than would be required by high efficiency motors with the same horsepower rating; however, this small percentage amounts to several hundred MW on the Ontario Hydro system and some promising demand management potential.

Ontario Hydro has a program to publicize high efficiency motors and to help customers evaluate the value of the electricity savings that they might gain. In addition, an experimental financial incentive is being offered to customers in a test area if they purchase motors above a specified efficiency standard. The experiment is scheduled to last until the end of 1989, when the information about customer acceptance will be evaluated. Other possible initiatives include working with manufacturers of equipment to encourage them to incorporate high efficiency motors without the buyer having to specify them, and also studying the effectiveness of an incentive to distributors (as opposed to consumers, as in the test area). Another approach is mandatory standards, similar to those mentioned in the previous section.

3.6 Motor-Driven Equipment

In general, more efficient designs of equipment such as fans, pumps, and compressors would reduce the electricity used by the motor driving it. It is thought that improvements are also available in better matching of equipment to the task at hand and in innovative equipment such as variable speed drives.

One approach to driven equipment efficiency is to offer an incentive for selected high efficiency models of pumps, etc. This requires comprehensive knowledge of the designs and costs of the available equipment and how it is used. Hydro has this knowledge for motors and is developing expertise in the area of driven equipment. Another approach is to have comprehensive energy-use audits done for customers, specifying that the auditor (usually a

consulting engineer) identify processes or equipment which could be more efficient. Information about the costs and benefits would be given to the customer, and a program of financial incentives could be offered provided that they meet a cost- effectiveness criterion.

3.7 Lighting

Another large use of electricity is in lighting. Market research indicates that many commercial customers have a low awareness of available equipment such as high efficiency ballasts for fluorescent lights. Furthermore, many developers seem to choose standard forms of lighting fixtures and configurations even when it would be relatively straightforward to do otherwise, such as in new buildings or during major renovations.

One marketing activity is to develop and distribute information about the efficiency of various products. Customers and contractors also need information about the optimal spacing of fixtures and task-lighting, to avoid overlighting. Offering financial incentives for particular ballasts and fluorescent tubes is one means of demonstrating the cost and energy savings possible. An experiment with this approach is in the planning stage. If a method were developed for identifying developers of new buildings or renovations early enough in their planning, incentives could be offered for the most efficient products and layouts at the same time. Financial incentives could also follow from an audit program of existing buildings, where the technical potential for conservation is probably greater.

3.8 Heating, Ventilating, and Air Conditioning

High efficiency electric chillers use large heat transfer areas and more efficient components such as motors. Ventilation can be made more efficient in many cases by balancing air flows and using variable air volume systems. More efficient lighting can reduce the need for cooling and ventilation, because there is less heat produced by the lighting.

The most efficient systems involve multiple heat pumps, coupled with a heat recovery system. Since large buildings typically require cooling even in cold weather except near the exterior walls, such systems are capable of removing heat from one area and adding it to another.

The current program involves developing and distributing information to builders and building managers. The information centers on equipment options but it also covers topics such as the importance of equipment maintenance. Future programs could include financial incentives for efficient equipment, air balancing tests and adjustments. By reaching developers early in their decision-making, Hydro might be able to encourage designers to incorporate multiple heat pump loops into their buildings. In cases where the building was likely to be heated by a conventional electric method, a substantial financial incentive for a more efficient system might be feasible.

3.9 Energy Management Systems

Energy management systems are control systems which are most frequently used by the customer as a load-shifting device. They also have potential for conservation, however, as equipment can be turned off automatically when not in use. The control can be relatively straightforward, such as a timer which reduces lighting and space conditioning when the building is normally not in use, but which allows for an easy zone-by-zone override by occupants working at unusual times. Some control systems use complex mechanisms such as devices which automatically dim lights near the window when the sun is shining, and motion detectors which turn off lights and other loads when no motion has been detected for a set period of time.

A demand-side program in this area could consist of information about the features and effectiveness of various systems. Compiling the information and staying abreast of developments would require considerable effort. Another approach would be to support standards for reliability of these systems. An incentive program would serve to defray the cost of zoned lights and space conditioning, which enable conservation in one part of the building while another part is in use. While such a program would be complicated to design and administer, it could contribute significantly to Hydro's demand management and customer satisfaction objectives.

3.10 Architectural Features

There is a number of innovative and efficient design elements, particularly for commercial and institutional buildings, which can be incorporated at the architectural stage and are never available

thereafter. These elements include carefully designed atria which let light in through a smaller space and diffuse it with mirrors, instead of the usual design which has a large area through which heat can escape. A similar feature is "day lighting", which is the careful design of windows and ledges to allow a maximum of natural light into the work-space. Another element is use of double walls, to trap heat inside similar to a greenhouse. The use of architectural features is complex because they tend to be costly and they must suit the building occupants' needs and tastes. Furthermore, the optimal design varies from place to place depending upon winter and summer climates, and variables such as the angle of the winter sun from the horizon.

An electric utility program to encourage electricity-saving features would rely heavily on information to customers and to the architectural community. The information might include comparisons of the electricity consumption of efficient and inefficient buildings in the service area, and forecasts of future electricity costs to compare against the cost of the features. Another approach is to sponsor design competitions. A more ambitious program could involve cooperating with the developer at a very early stage of a project, perhaps paying the fees for efficient features to be designed and then giving the developer the option to choose it or not. Hydro has a consulting study under way in which an architectural firm is studying the applicability of innovative electricity-saving features to the Ontario situation.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT D

RATES AS A DEMAND MANAGEMENT TOOL

October 1987

Market Services and Development Division

CONTENTS

1.0 INTRODUCTION

Demand management is defined as actions intended to influence the amount or timing of customers' use of electricity. The purpose of this report is to survey the variety of rate structures which may be useful as instruments of demand management.

It is a helpful analogy to speak of the rate structure as a "tool", but it is perhaps more accurate to think of it as a tool-kit. The specific rate structures, which are the tools in the kit, include time-of-use rates, both mandatory and optional, applied either to many customers or confined to customer groups who are most likely to respond.

Another tool which has gained attention from time to time is interruptible power. There are a number of other structures which are not as widely known or recognized as having potential for demand management.

Section 2 gives a brief history of the development of rate-making objectives in Ontario since 1976.

Section 3 describes and evaluates ten rate structures which are used or have been suggested as tools for demand management.

Section 4 of the report is a summary, together with the conclusions that can be drawn. The principal conclusion is that rate structures can be potentially very powerful tools, but there are important factors which will tend to limit the extent to which some of them can be used for demand management objectives. These factors include the existence of rate-making objectives other than demand management, and the lack of precise knowledge of the effect of rate changes and time lags in these effects. Hence, there is the need to consider implications in addition to the desired impact on demand.

2.0 RATE-MAKING OBJECTIVES AND THE EXISTING RATE STRUCTURE

2.1 Development of Rate-Making Objectives

Early rates in Ontario were generally in the form of unmetered rates based on the floor area lighted or the horsepower of the connected load. These rates gave way to metered rates. The first formal analysis of rates was carried out in 1918, followed by a detailed study in 1922-3 to determine whether, under the then existing structure, each consumer paid his share of the cost of service. There have been numerous examinations and rate structure modifications since then, aimed at living up to the slogan "Power at Cost".

There were two trends in the 1960s that are noteworthy. One was toward simplification of rate structures, with the phasing out of many detailed riders on rates and a reduction in the number of rate classes. Another trend was renewed interest in formal cost-of-service evaluation methods, including consideration of time-of-use variation.

The goal of retail rate simplification was pursued further in the 1970s, with a concerted effort to phase out special rates for water and space heating.

In 1976, Ontario Hydro published the report from its study of the principles of electricity costing and pricing (ECAPS). A hearing was held before the Ontario Energy Board between March 1977 and June 1979, and the OEB issued its report to the Minister of Energy in December 1979. Ontario Hydro developed a framework for rate-making which was consistent with the main principles of the OEB report but which did not adopt all of the specific recommendations. The framework was used to design illustrative rates which were then discussed with customers and interested parties. In October, 1981, the Ontario Hydro Board of Directors approved the development of bulk rates based on the following four objectives:

- Rates should recover the annual revenue requirement.
- Rates should be fair - broadly defined as those which track costs and assign equal treatment to equals based on cost causality, to the extent feasible and practical.
- Rates should encourage efficient use of facilities and resources in the production, distribution and consumption of electricity so as to minimize costs to Ontario Hydro customers over the long term.
- Rate structures should be publicly acceptable and comprehensible, and should be stable and feasible in application.

For convenience in referring to these objectives, they will be called respectively:

- "revenue requirement"
- "cost tracking"
- "demand management"
- "acceptance"

The efficiency objective has been labeled "demand management" because it is broadly equivalent to the focus of demand/supply planning.

The first attempt to design bulk rates in accordance with these principles was the proposal for 1983 bulk electricity rates. The major features were time-of-use energy rates and demand rates, a shift toward higher energy rates and lower demand rates, and retention of interruptible power discounts. The OEB accepted the proposal, with certain adjustments. The proposed changes were ultimately deferred, however, at the request of the Minister of Energy, because of financial impacts on some customers which were deemed to be unacceptable. The proposal for 1984 bulk rates was based on the same general policy as that of the previous year, although it differed in some details. The 1985 proposal stressed a gradual approach to rate reform and in its proposal for 1986 rates, Hydro deferred any further implementation for three years.

As noted by the OEB in the 1979 report (H.R.5), rate-making objectives are interdependent and there may be some conflict amongst them. There are three points that should be noted:

- The first objective, that the rates as a whole should recover the annual revenue requirement as closely as possible, has been given primacy over the other objectives in all of the rate proposals, and this has not been questioned by the OEB or most participants in the public hearings.

- The delays and current hiatus in rate re-structuring have stemmed mainly from conflict between the cost-tracking and acceptance objectives. (In a nutshell, restructuring rates to better reflect patterns in cost causation has not gained public acceptance. This includes both daily and seasonal variation; and also the ratio between capacity-related and energy-related costs. This is discussed further in Section 3 under the headings Time-of-Use Rates and Demand Rates.)

- There have been rate changes in response to the demand management objective, despite some conflict between this objective and the acceptance one. (This is discussed further under the headings Interruptible Rates and Special Condition Rates.)

2.2 The Existing Rate Structure

As noted above, the dominant objectives of electricity rate-making in Ontario have been collection of the annual revenue requirement and allocation of this amount to customers and groups of customers based on cost causation. The structure of rates is influenced by the structure of the electricity supply industry. In Ontario, the distribution of electricity is usually a municipal responsibility. Ontario Hydro generates and transmits wholesale electricity to the over 300 municipal electric utilities who in turn distribute to most of the province's 3.2 million end users.

In addition, Ontario Hydro supplies electricity in bulk directly to over 100 large (over 5 MW) industrial customers, and distributes to about 800 thousand residences, farms and smaller commercial and industrial customers through its rural distribution system. These direct industrial and rural customers are retail customers and are served by Ontario Hydro only where municipal utilities do not exist or are unable to serve them.

Wholesale Rates:

The wholesale rate to municipal utilities has two parts; the demand rate and the energy rate. The demand component is a charge for the maximum demand or rate of energy consumption in the month. This charge is intended to recover costs related to providing the capacity necessary to serve customers reliably. The demand charge varies inversely with the voltage level at which the utility is served. That is, the higher the voltage, the lower the demand rate. This differentiation based on voltage level helps to ensure that only customers actually using a part of the system pay for that part. The energy component is a charge for the total amount of energy delivered during the month. This charge is intended to recover costs related to the provision of energy. The wholesale energy rate is a "flat" one, meaning that there is no variation in the rate based on voltage level on the amount of energy used.

Retail Rates:

Retail rates are those charged to the end users of electricity. The retail rate structure is generally standardized across the province's municipal utilities and Ontario Hydro's retailing arm. While the structures are generally consistent, the rate levels vary among retailers. The following discussion applies to both municipal utility and Ontario Hydro retail rates.

i) Large User Rates:

Large users are retail customers with a billing demand of more than 5,000 kW. About 120 such customers are served by municipal utilities and about 100 more are served directly by Ontario Hydro. Ontario Hydro's large use customers and large users of most municipal utilities pay two-part demand and energy rates similar to those of the wholesale schedule. In the case of two municipal utilities, large users pay rates similar in structure to that described under "General Service Rates", below.

Large user demand rates also vary inversely with voltage level, and the energy rate does not vary with voltage level or the amount of energy used. Because of differing cost and load characteristics, the demand rates are lower for large users than for municipal utilities at like voltages, while the energy rates are higher.

ii) General Service Rates

General service rates apply to all customers taking less than 5,000 kW except residential customers. These rates have a multi-component structure using both blocked demand and blocked energy rates.

There are usually (depending on the utility) four energy blocks, the first two being the first 250 kW.h per month, then the next 12,250 kW.h. The third block varies in length in order to achieve a smooth transition from the general service rate to the large user rate at 5000 kW. The remaining (or balance) block is priced at the energy rate for large users.

The general service demand rate, which is much lower than the wholesale and large user demand rates, is applicable to maximum monthly demand in excess of 50 kW. The demand rate is not applicable to the first 50 kW, since such low demand is not cost effective to meter.

iii) Residential Rates

Residential rates have only a blocked energy component; there is no demand charge. There are usually two blocks: the first 250 kW.h per month and the balance. The price of the first block is higher than the second. The price of the second block covers the average variable cost of electricity delivered to residential customers. The additional charge on the first block is designed to recover those costs which do not vary with level of consumption, such as the costs of service conductors, meters, meter reading and billing.

3.0 RATE STRUCTURES

The purpose of this section of the report is to outline the way in which various rate structures can contribute to efficient use of resources, and to discuss whether they are also consistent with the other rate-making objectives.

3.1 Curtailment Pricing

From a demand/supply point of view, the strongest price tool is curtailment pricing, in which the price is set specifically to limit the quantity demanded to no more than the capacity of the system. The primary task of the price is to "curtail" demand to the level of capacity. Whenever this is not necessary, ie, when demand is low relative to capacity, the price is set at the short-run marginal cost. (Another name for this concept is "short-run marginal-cost pricing".) However, if price must be raised above long run marginal cost in order to keep demand within system capability then some cost effective (economically efficient) uses of electricity will be discouraged. At that point it would be more economic to build new capacity than to increase price to supress demand.

The distinctive characteristic of curtailment pricing is that it does not aim to raise a specific amount of revenue; the objective of "revenue requirement" is simply not relevant. This is probably the main reason why curtailment pricing has not been used in any major public utilities over any significant period of time.

A muted version of curtailment pricing is found in the idea that the annual revenue requirement should be increased during periods of prosperity and rapid growth, and decreased during recessions, such that the major investments are amortized mostly during the high growth periods. The idea is that the higher price imposed during the rapid growth will serve to decrease the growth in demand and enable the utility to keep pace, and conversely the lower price will stimulate demand and utilize resources that would otherwise be idle. The first rate-making objective is retained, but the annual target is varied to accommodate the third objective (ie, efficient use of resources).

Curtailment pricing has not been recommended by Ontario Hydro or the Ontario Energy Board. The annual revenue requirement is not a function of any variable reflecting the balance of demand and resources. Rather it is set on the basis of annual accounting costs, including sufficient net income to maintain variables which indicate financial soundness.

The main reason for listing curtailment pricing in this report is because it may be the most effective for achieving the "demand management" rate-making objective alone, assuming the other objectives become secondary. The rate structures considered in the remainder of the report are retreats in one way or another from this "ideal", in other words, they are less effective or at least more complicated tools for demand management, dictated by the other tasks required of the rate structure.

3.2 Spot Prices

In spot pricing, there are a number of possible prices established at the beginning of the rate period (say four different rates ranging from 1¢ to 16¢ per kW.h). Which of these rates will be in effect at any particular time is not determined in advance. The highest rate will apply during times of very high cost or system overload. The lowest will apply when costs are lowest, and so on. The idea, of course, is that the customers paying spot prices will decrease their consumption when the price is high.

In practice, the customer would likely be given the assurance by contract that the highest rate would not apply more than say 2% of the time, the lowest at least say 20% of the time and so on. One reason for this is that spot pricing is generally thought of as a voluntary option, in contrast to curtailment pricing which would have to be mandatory to be fully effective. The commitment on hours of availability of the lowest price would serve to assure the customer that he would not be out-of-pocket compared to regular rates.

Spot pricing is attractive to customers who are able to pay constant attention to the price of electricity and can schedule their consumption away from high-cost periods without knowing far in advance when those hours will be. Most customers do not meet these criteria. Nevertheless, there are utilities experimenting with spot pricing to industrial customers.

There is potential conflict with the fourth rate-making objective, concerning feasibility and public acceptance. Also, with spot pricing as with other voluntary options, it is reasonable to expect that the customers who are unable to take advantage will want to be assured that the utility is getting its money's worth from those customers who do take advantage of the option. For example, the spot prices should not be set so low or the peaks so short that certain customers can gain a windfall without shifting very much (or any) of their consumption away from the peak period. In addition to these difficulties, passing such rates on to customers of municipal utilities would require two layers of communication and rate making. Thus, while not insurmountable, the costs of overcoming these complications may not be insignificant. Careful evaluation of the potential benefit would be required before implementation.

3.3 Interruptible Rates

The interruptible rate option gives certain large customers a lower electricity price in return for a commitment to decrease consumption to a pre-determined level when asked to do so. Ontario Hydro has used this form of demand management for a long time. In its present form, it is called Capacity Interruptible. The customers are asked to cut their load to their respective pre-determined levels only under conditions where the system does not have capacity available to meet demand. The expected number of such hours is small, but it can occur when there is a combination of high load and forced outage. Hydro commits to not interrupt more than a certain percentage of the time during any particular time period.

The cost saving from Capacity Interruptible is that it is not included in the load for which load-meeting capability is planned, because, up to a certain level, supplying interruptible loads does not increase the need for generating capacity. The expected level of response to a call for interruptions is now about 500 MW. Without it, the generating system would have been planned to be larger by about 625 MW, allowing for planning reserve. There are savings attributable to interruptible power even when there is surplus capacity, because the less efficient plants can be "mothballed" and/or purchase commitments can be lower than would be the case if that power were being delivered as "firm power". The discount for interruptible power (compared to regular rates for firm power) is determined by this cost saving.

Until recently there was a second class of interruptible power which had a larger discount and had more hours of interruption. The customer could be asked to cut back his consumption not only when capacity was short, but also when a plant with high operating costs was going to be required to operate. The specific mix of generating plants in the Ontario Hydro system at present does not warrant this option.

The similarities between interruptible power and spot pricing are obvious, particularly in that the signal to reduce consumption is given only when it is required which is not predictable far in advance. Since this signal is given only a small amount of the time, it can be a strong signal. Of the two options, interruptible power is less flexible because it has only two "states" - either the customer is interrupted or he is not - whereas spot pricing can have signals of varying intensity.

Interruptible rates are extended to customers of municipal utilities through a contract provision called a tri-party agreement. Ontario Hydro communicates directly with the municipal utility's customer in the event of an interruption, so the response is just as rapid as from customers served directly. The municipal utility gives the customer the rate incentive, and in turn is compensated by Ontario Hydro.

3.4 Time-of-Use Rates

The principal difference between time-of-use rates and the structures discussed under the previous two headings is that, under time-of-use rates, the time periods are determined at the beginning of the rate period. In fact, it would be expected that the time periods would shift very little if at all from one year to the next. This rigidity is obviously a disadvantage from the demand management point of view. However, it enables the customer to schedule consumption far ahead, knowing that the off-peak incentive will be there. This would enable many customers to respond to time-of-use rates who cannot respond to the less predictable incentives discussed earlier.

The distinction between seasonal rates and time-of-day rates should be made clear. Both are called time-of-use rates. Time-of-day rates are associated with the idea of load-shifting, ie, the response to the peak price is primarily to re-schedule consumption to a nearby off-peak period. It is interesting to note that, from 1909 to 1938, there was a time-of-day discount for a class of restricted power service. Seasonal rates, on the other hand, are associated more closely with the idea of increasing efficiency of machinery and appliances which are operated mostly in the winter. In some cases seasonal rates are compatible with dual-fuel applications.

Time-of-use rates, both seasonal and time-of-day, were proposed by Ontario Hydro for its 1983 bulk rates. Ontario Hydro submitted that time differentiation of bulk rates, based on accounting costs, is not discriminatory and leads to more efficient utilization of the system. The Ontario Energy Board accepted the proposal for 1983, and endorsed the concept again in two subsequent reports. A considerable number of customers and their representative organizations, on the other hand, have found time differentiation to be unacceptable. They have made successful representations to the provincial government and Ontario Hydro. As outlined in Section 3 above, the result is that there is a commitment to not re-introduce this feature into bulk rates before 1989.

Time-of-use rates at the retail level are also relevant, but would make sense from the municipal utility point-of-view only if the bulk rates were also time differentiated. Retail time-of-use rates require meters and billing procedures which are more costly than current practice. Ontario Hydro has cooperated with the municipal utilities in conducting an experiment, with time-of-use rates being applied to 500 residential customers and 60 general class customers across the province. The preliminary results from the residential class indicate that load shifting and load reduction do occur; analysis of the final results is required to establish whether such rates are a cost-effective means of doing this.

There is an optional time-of-use rate available to larger customers called Scheduled-Hour Power, (or in some cases Valley Hour Power). If a customer contracts to have his individual peak during a specified off-peak period, then he gets a discount on the amount by which his off-peak maximum demand exceeds his peak-period maximum demand. Because of the data required to calculate these various parameters, the option is available only to customers with suitable meters. In any case, the option is of no interest to a customer who could shift some consumption to off-peak times but not so much as to have his off-peak level exceed his peak-period level.

It may be noted that time-of-use rates can be either mandatory or voluntary. The voluntary option is usually thought of as applying only to retail rates. Voluntary rates are obviously less effective as a demand management tool, but may be accepted more readily by customers. It may also be noted that either voluntary or mandatory rates can be applied across-the-board to all customers or selectively to only a selected class of customers. If the latter, the selection would be on the basis that the customers are large enough to make the additional metering and administrative cost worthwhile or that their particular uses of electricity make them more likely to respond by shifting or improving efficiency.

3.5 Demand Rates

3.5.1 Non-Coincident Demand Rates

The demand rate is a monthly charge, based on the customer's own highest 60-minute consumption in the month. Until 1946, the direct industrial rate consisted of only a demand charge. This was then augmented by an "excess energy charge" applied to customers with load factors above 70%. In 1966, the present form was introduced, consisting of separate demand and energy charges. The objective of the re-structuring was to de-emphasize the demand rate and provide a stable and realistic value for the energy rate. In addition to the regular rate, discounts from the demand rate have been available to encourage the large customers to take a portion of their power on an interruptible and/or scheduled (ie, daily off-peak) basis thus saving generation capacity.

Many customers have increased their own load factors in response to the demand rate. Amongst bulk customers, large industrial customers take care to schedule shifts and operations so as to flatten demand. Some utilities offer incentives to their retail customers to consume less at the time of the utility peak, and others advertise to their customers asking them to avoid the peak. Utilities in turn charge non-coincident demand rates to their larger customers. Many such customers have "energy-management systems", which are computerized systems to schedule devices so that they do not operate simultaneously.

All of this adds up to a considerable amount of load shifting by individual customers. How much is not known. For instance, it is not known how much impact it has on the system load shape, since the shifting is done to avoid individual peak demands which tend to occur at different times. It is easy to imagine hypothetical situations in which a customer, retail or bulk, decreases its own peak by shifting load but aggravates the peak of the supplier.

The other aspect that should be noted is that, with a given revenue requirement, a higher demand rate implies a lower energy rate. Ontario Hydro's intention has been to decrease the demand component while increasing the energy component, which has been the long-term trend. The objective behind this is better cost-tracking, ie, a fairer reflection of the respective levels of capacity costs and energy costs to Ontario Hydro.

From a demand management point of view, the net effect of the present demand:energy split compared to a lower demand:higher energy split is a higher incentive for load shifting and a lower incentive for energy efficiency. As with time-of-use rates, Ontario Hydro's proposals to decrease demand rates and increase energy rates have been broadly acceptable to the Ontario Energy Board, but unpopular with influential customers. In arguing against such a change, the latter group makes the point that individual customers would be less concerned about their individual load factors and that the system peak would increase while overall system output would decrease. The impact is difficult to assess quantitatively. The objective in proposing to change the ratio has not been related directly to the demand/supply situation, but rather to improve cost tracking.

The interaction between the proposed demand:energy ratio and the proposal for time-of-use rates should be noted. In the 1983 proposal, the "lower" demand rate was in part due to the fact that the demand rate for billing demands established in <u>off-peak</u> daily periods was reduced greatly, and was reduced also in the off-peak <u>season</u>. Furthermore, the energy rates were structured to signal the customers to shift load where possible to the off-peak. The thrust is to shift load away from the peak season, which admittedly is more difficult for the customer to accomplish than shifting from the short daily peak of the individual customer himself. To summarize, it is not correct to conclude that lower revenue from the demand rate is tantamount to a reduced incentive for load shifting.

3.5.2 Coincident Demand Rate

This variant is not widely used, whereas non-coincident demand rates are used by virtually all utilities. Under this option, the customer is billed for the level of his consumption at the time of the utility's peak - hence "coincident" demand. (He is also billed for his energy consumption over the whole period.) It can be seen that coincident demand billing corrects the anomaly that was described for non-coincident demand, ie, the customers who increase the supplier's peak while decreasing their own, at considerable cost to both.

Concerning the choice between non-coincident and coincident demand rates, the theoretical appeal of the latter for demand management purposes is obvious. In practice, the comparison is less clear. For retail rates, there would be some upgrading of metering of retail customers required. More important, coincident demand rates will coordinate load shifts to everyone's advantage only if the consumers of electricity know when the peak is likely to be and can limit or shift their loads accordingly. Most retail customers cannot pay this amount of attention to their electricity use, even if the predictions could be passed through to them. There may be a practical application of the coincident demand rate at the the bulk level, with utilities passing the price signal through to a small number of customers, or alternatively passing it through as an incentive for customers to allow direct utility control of their loads. The feasibility of coincident demand billing would also be enhanced if the interval over which peak demand is measured were longer (ie, several hours rather than one hour).

3.6 Inverted Rates

The most usual rate structure for residential, farm, and small commercial customers is a "block" rate described in Section 2.2. The customer is charged for energy only, not demand. The price varies for successive "blocks" of energy, say 9¢ per kW.h for the first 250 kW.h in a given month and 5¢ for any consumption beyond that. The existing structure, a "declining block" rate, has downward steps, such as just illustrated; an "inverted" structure has upward steps with the first block having the lowest price and the second and any successive blocks having a higher price.

The rationale for downward steps is that, due to fixed costs, the unit cost of supplying a large customer is lower than that of supplying a smaller customer. The lowest price covers the average variable cost, and the additional charge on the first block(s) covers unit fixed costs. Thus all customers pay the variable costs incurred for them, and all except the smallest ones pay an equal share of the fixed cost (such as lines and administration).

There are two possible rationales for inverting the steps. One is the lifeline rate concept, in which all customers get a small subsistence amount of electricity at a low price not based on cost, and customers who consume more than this amount pay a correspondingly higher price. This concept has not been proposed by Ontario Hydro or the Ontario Energy Board, because it is inconsistent with the cost tracking objective. In any case, it has nothing to do with demand management.

The second rationale is that in the downward step structure, the price for the final block is too low and should be raised. The earlier blocks would be lowered to allow for a constant contribution to the total revenue requirement. Some advocates would prefer the price on the final block to be set at long run marginal cost, and others would prefer it even higher to induce more conservation. The argument is that the power in these higher blocks is used for discretionary purposes and/or for uses where other energy forms could be used (eg, space heating).

A variant is to abandon the block rate form and have a single rate regardless of the amount used. From a cost-tracking point of view, this is a muted form of inversion, because it ignores the distinction between fixed and variable accounting costs. From a demand management point of view, the uniform rate is not a very flexible tool.

For completeness, it may be noted that block rates are compatible with seasonal and time-of-day rates. The resulting structure would be more complicated. The rationale for inverting the blocks might still apply but would be less strong, insofar as the price for large consumption would be higher in peak periods.

In summary, a move to inverted block rates would be a step toward the third objective, demand management, and away from the second objective, cost tracking.

3.7 End-Use-Specific Rates

Separate rates for specific machinery or appliances are not very common. In few if any cases is there a separate meter used for this purpose. The policy established in the early 1960s was that there should be a general rate to fit all consumers in a rate class, on the basis that separate billing and/or metering was confusing and costly.

There are two rate structures which have been used for water heating. One is the flat monthly rate, which is unmetered. The other is a separate block within the block rate structure, available only to customers with electric water heaters.

End-use rates tend to be lower than the regular rates, probably because any that are higher than regular rates would be difficult to enforce. A specific rate would therefore tend to be found for loads which are less costly to serve than the average mix of uses. From a cost-tracking point of view, the flat rate is not very good, but the separate rate block might be justified by this objective.

From the point of view of demand management, specific rates tend to be associated with promotion or maintenance of load rather than conservation. However, the normal rate tends to be higher, to the extent that the specific rate removes the influence of the less costly off-peak loads, so that there may be some tendency toward conservation of the loads not covered by the specific rate.

3.8 Load Management Incentives

The topic of direct load control is beyond the scope of this paper. For completeness, it should be noted that the incentive for load control is usually a monthly credit or an end-use-specific rate. (There may also be a capital incentive at the time of installation. However, the monthly incentive assures continued availability of the control option.) The flat rate for unmetered water heating, where it is available, applies to those which are subject to direct load control.

A variant of direct load control is "demand subscription", in which the customer responds to a signal supplied by the utility to the customer's home at peak times. The customer reduces loads to a previously subscribed level, but has the choice each time as to which uses are reduced to reach this level. In an experimental implementation by Southern California Edison Company, the customer has two minutes to reduce load if his load exceeds the pre-set level during an alert, or the device will cut off service. Demand subscription has been estimated by Southern California Edison, on the basis of its experiments, to reduce consumption by about 2.4 kW per participating household.

Most existing load control is designed for short curtailment, to enable a distributing utility to decrease its non-coincident billing demand under the bulk rate structure. The usual period of curtailment is too short to be of much interest for demand/supply planning. (As described in Section 3.5.1, it also has the potential to be perverse for the bulk system's requirements.) At this stage, it is not clear that an incentive which is high enough to encourage long period interruptions can be economically justified; one reason that it has to be this high is because the incentive for short period control based on the local system viewpoint is so lucrative.

3.9 Special Condition Rates

Special condition rates are included in this report for the sake of completeness, because they are clearly a tool for demand management. However, they are intended to promote fuller utilization of existing facilities and will be phased out when appropriate. In that way they are not relevant to the topic of demand/supply planning.

These rates are available to customers who are able to establish that they will use a large amount of electricity at an incentive rate level which they would not use at the regular rate. The incentive rate is set at the cost of production plus a margin. Any specific incentive rate is set within the range of production costs, depending on variables such as the proportion of peak and off-peak power in the agreement and the length of time that it covers. These rates are planned to be available only as long as there is expected to be base-load capacity which would go unused at the regular rates.

3.10 Purchase Rates for Parallel Generation

The purchase rate is one part of the incentive for independent generation of electricity, applicable to those parties who can generate more than their own requirements. The larger topic of independent generation is beyond the scope of this report.

Obviously, the higher the purchase price and the longer the commitment by Hydro, the greater the availability of independent generation is expected to be. It is proposed to offer two rates for such purchased power, the higher one being for power above a particular monthly load factor which provides a predictable source of supply, and the lower one for less reliable sources. There is an additional incentive for electricity generated from renewable resources and with reliability in the higher category.

This additional incentive can take the form of either a capital incentive or a long-term commitment to a fixed purchase price.

The concept of "avoided cost" is central to the determination of the purchase price to be offered. The avoided cost includes the cost of Hydro-owned capacity which can be postponed. Since purchase rates are calculated for the long term and apply to peak periods, it is consistent that they should be higher than range rates which are calculated for the short term and must have a higher proportion of off-peak power.

4.0 SUMMARY AND CONCLUSIONS

Four rate-making objectives have been followed in setting electricity rates. The ranking of precedence of these objectives strongly influences the structure of the electricity rates. The dominate objective has been that the electricity rates are to produce revenue equal to Ontario Hydro's annual revenue requirement. The other objectives address efficient use of resources (which closely matches demand management objectives), setting rates that fairly represent the cost of supplying electricity (cost-tracking), and setting rates that are publically acceptable and reasonably stable over a period of time.

If emphasis is given to demand management the following changes in the rate structure might occur:

- development of spot pricing as an option for some customers;

- continuing review and updating of the rates for interruptible power, load management and purchases from private generation, to ensure that the rates are as high as can be justified and that the contract conditions are as flexible as possible;

- rates would vary with time-of-use at the bulk level, and time-of-use rates would be available to more retail customers, at least as an option.

If there is a greater need to reduce load growth, to the point that cost tracking and acceptance objectives become secondary, the following changes would be worth considering:

- inverted rates, with the rate block for larger customers set above long-run marginal cost;

- coincident demand billing, at least at the bulk level;

- time-of-use rates with a large differential between peak and off-peak;

- mandatory rather than optional time-of-use rates at the retail level.

The conclusion is that the rate structure provides some very powerful tools for demand management, especially when applied to customers for whom electricity is a major cost component. However, rate structure tools are not very flexible, because using them has important implications beyond the desired impact on demand.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT E

PUBLIC AND GOVERNMENT CONSULTATION

October 1987

Corporate Relations

3449G

1.0 Introduction

In 1984, Ontario Hydro undertook a Demand/Supply Options Study to examine ways of meeting Ontario's electricity needs in the 1990's and beyond. As an integral part of this study process, Hydro developed and implemented a public consultation program to determine the concerns, priorities and opinions of customers, individuals and organizations throughout the Province on ways to plan for future energy needs and preferred options.

Public involvement programs have been an important part of Ontario Hydro's planning process for new generation and transmission facilitites for the past 15 years. Between 1976 and 1983 Hydro undertook a series of studies with provincial organizations to review the processes for siting generation and transmission and for public involvement. One of the recommendations of the latter study was that public involvement be extended to all aspects of Ontario Hydro's planning process.

This document describes the programs developed to meet the needs and expectations of Hydro's many publics, and summarizes the results and key findings of these programs. Views expressed by program participants are summarized without evaluation of their factual accuracy or consistency with other information sources.

2.0 Objective of Public Consultations

The primary objective of the Demand/Supply Options Study is to ensure that Ontario Hydro can continue to serve the public providing reliable service, keeping rates reasonable, protecting the environment, ensuring public safety and using technology that is appropriate for Ontario.

Conditions in Ontario change every day; energy requirements are continuing to grow. Ontario Hydro's mandate requires that it plan for electricity requirements. Electricity requirements can be met by either increasing the supply or by taking measures to decrease the demand or by doing both.

The objective of public involvement in planning for electricity needs is to ensure that Ontario's electricity industry will continue to provide a power system that reflects the needs and priorities of the people of this province.

A broad range of approaches has been used to date to inform Hydro's many publics of the study, to provide opportunitites for these publics to be involved in the planning process and to respond to the concerns and priorities expressed by these publics.

3.0 Elements of Hydro's Public Consultation Program

Planning for these consultation and communications programs began early in 1985. Background research included focus groups, pilot tests, review of

prior survey results and discussions with other utilities and consultants. Programs focussed on several key publics:

- special interests which may be affected by the options or plans, as represented by provincial organizations;
- community leaders active in public affairs in communities across the province;
- residential, commercial and industrial customers;
- municipal utility commissioners and managers;
- members of the general public having an interest in Hydro's activities, programs and policies.

Consultation programs were designed to increase the awareness of participants of the need for planning, the options available and to seek their views on planning issues. These programs were not designed to seek consensus, but rather to obtain a range of opinions from a wide cross-section of the Ontario public. The focus was on concerns, priorities and values regarding the planning process rather than the technical aspects of particular options.

Communications efforts were designed to make information available to many of Hydro's publics on these planning activities and the range of options. The title "Meeting Future Energy Needs" was adopted as the theme. Communication vehicles included speaking engagements, audio-visual and printed materials, and an energy planning simulation program for secondary students.

The following sections provide an overview of the consultation programs.

3.1 Provincial Organization Consultation

A cross-section of special interests represented by approximately 125 organizations was invited to participate. Fifty-eight organizations responded to the invitation representing industry, agriculture, commerce, labour, recreation, the community and the environment.

Hydro participants included the Chairman, a member of the Board of Directors, the executive vice-presidents and a number of vice-presidents, directors, managers and planning staff. A staff member of the Select Committee on Energy attended the sessions as an observer. Five meetings held in Toronto between November 1985 and February 1986, focused on policy matters, priorities and values in electricity planning. A document entitled "Meeting Future Energy Needs: An Initial Review of the Options" (651SP, November 1985) prepared by Hydro's planning staff was provided to participants. The report describes Hydro's planning process and the range of options under consideration.

Organizations were asked to submit briefs addressing six questions suggested by Ontario Hydro as well as any material they felt was relevant. Thirty-six submissions from one page letters to briefs over 50 pages long were received. Hydro responded to each of these contributions.

Results of the program are described in detail in the three volume Reference Document - Provincial Organization Consultation Program-SC586002/1-3.

3.2 Regional Consultation Program

Obtaining the views of a cross-section of residents in communities across the Province was the objective of this program. To achieve this, 20 to 30 community representatives active in public affairs were invited to each of 13 meetings held throughout the Province. Meetings were held between January and June of 1986 in: Sarnia, Chatham, London, Hamilton, Port Hope, Kingston, Winchester, Alliston, Bracebridge, North Bay, Sudbury, Timmins and Atikokan. Overall attendance totalled more than 300.

A local resident was asked to act as moderator and reviewer of the minutes. Invitations were sent to people involved in agriculture, business, education, the environment, women's issues, labour, social welfare and public affairs. Invitess received a copy of a speech, entitled "Meeting Future Energy Needs", given by the Chairman, or a summary booklet entitled "Energy for the Future".

Each meeting began with a presentation by Hydro staff on planning for future energy needs and the importance of hearing public advice and priorities. A Hydro video entitled "Beyond 2000" was shown at most meetings.

Following the presentation, a senior Hydro representative would begin discussion by asking questions such as: What is important in planning for future energy needs? What is Hydro's role and mandate in meeting them? How should the trade-offs be made among the options? Community participants, Hydro executives, Regional and planning staff then explored and exchanged views during the discussion.

Minutes were kept and most meetings were tape-recorded. After a review for accuracy, the minutes were sent to participants. A questionnaire was sent after each meeting asking for comments on the proceedings and for more details about how Hydro should meet future energy needs.

Reference Document - Regional Consultation Program - SCS86003 provides details of the Program and its results.

3.3 Municipal Utility Consultation Program

Program objectives were to increase the level of understanding of elected and appointed municipal utility officials and to seek their comments about

the demand/supply planning process and the options. Utility commissioners and managers in Hydro's six regions, Municipal Electric Association representatives and senior executives, regional directors and planning staff from Hydro participated in the meetings.

More than 300 utility commissioners and managers representing 116 organizations attended the 10 sessions held between February and June of 1986. A liaison committee of representatives of the Municipal Electric Association and senior Hydro executives was established to provide for an ongoing dialogue on the study.

Reference Document Municipal Utility Consultation Program-SCS86004 provides an overview of the results of this program.

3.4 Market Survey

A survey of residential, commercial and industrial customers was conducted by Goldfarb Consultants for Ontario Hydro. It involved province-wide personal interviews with 1,200 residential consumers, 200 commercial and 200 industrial customers. Residential surveys were done in January and the commercial/industrial surveys in February, 1986.

The Goldfarb Market Survey Report provides details on the survey and its results.

3.5 Government Consultation

Ontario Hydro regularly keeps the Ontario and, as appropriate, the Federal Government, fully advised of significant planning activities which might result in additions to the bulk power system, or activities affecting power customers. In particular, the Ontario Government's interest in these and other Hydro-related areas underscores its responsibility for developing and implementing energy policy for the Province, and its responsibilities as detailed in the Power Corporation Act, Environmental Assessment Act and other legislation affecting Hydro.

In the case of Hydro's Demand/Supply Options Study, the Corporation has met with Provincial Government Ministries, and Federal Departments which might have an interest in the study, to acquaint them with the study's objective, schedule and information on the options. At the same time, an all party provincial legislative committee reviewed the study in detail.

The Select Committee on Energy was appointed on July 10, 1985 to "inquire into and report within ten months on Ontario Hydro Affairs." In its first session, 19 days of hearings were conducted in September and early October, 1985. The Committee examined the need for Darlington NGS.

The Committee's second session focussed on Hydro's planning process and the delineation of operating and policy making responsibilities between Ontario Hydro and the Government. In April 1986, the Committee held 12 days of

hearings on demand and supply options, Hydro's Demand/Supply Options Study and the process of choosing options. During this period the Committee heard from 64 witnesses including representatives from Hydro, filed 79 exhibits and received written submissions from 17 public and interest groups.

3.6 Communications Programs

Communication initiatives were developed for a broad range of audiences including those involved in the consultation programs. Between August 1985 and the end of 1986, more than 25 speeches by Hydro executives to a wide range of audiences have focussed on future energy needs. Also, about 15 presentations have been given by other Hydro staff through Hydro's Speakers Bureau.

More than 1,000 copies of an 80-page document describing the planning process and the options were distributed to consultation program participants, government and individuals. A 16-page brochure was prepared and more than 43,000 copies were distributed to government, municipal and business leaders, educators, visitors to Hydro offices and information centres and senior Hydro staff. Eight-minute and three-minute audio-visual presentations were produced for use at public meetings, information centres and special events. A 27-minute video production was made available to Cable TV companies. An exhibit on future energy needs was developed for community events and meetings.

A simulation game based on the Meeting Future Energy Needs Study was prepared for use in secondary schools. More than 2,000 students from 116 schools participated, culminating in a province-wide playoff in May 1986. The game was well-received by educators and was run again in the winter of 1986/87. Seventy-seven additional secondary schools registered to participate in the follow-up exercise.

3.7 Results of the Program

Public discussion of how future energy needs should be met has resulted in a broad range of expressed opinions, concerns, and priorities. Each of the following sections provide a summary of the significant findings on public attitudes and values on a specific subject. Major findings are summarized at the end of each section.

Public views on the importance of energy and life style, the need for electricity, priorities in planning, Ontario Hydro's role in energy planning and the Province's economy, the planning decision-making process, the options under consideration, strategic planning priorities and government involvement are presented. The text consists mainly of extracted quotes from the background reference documents mentioned in Sections 3.1, to 3.4.

Note: All publics are referred to as "participants," including those involved in the Market Survey.

4.0 Energy Use and Lifestyle

Public attitudes were sought in the Market Survey on the importance of energy use to an individual's lifestyle; future energy consumption; the Province's energy situation in the next 5-10 years; and the capability of the Province to respond.

Survey results indicate that Ontario residents place a high priority on a good life and upward mobility. The desire to improve one's lot in life and the goal of home ownership are still fundamental values. Interference with these goals is regarded as unacceptable. A secure, reasonably-priced supply of electricity is seen as vital to Ontario's quality of life and economic well-being.

People expect to have more appliances or electrical products, particularly those providing comfort and convenience (41%), to move to a larger home (15%) or expect their family size to increase (22%). An expectation that energy consumption, particularly electricity, will increase in the future is evident.

Electricity is seen as the energy source that has contributed most to Ontario's economic and industrial development over the years. Given public perceptions of its abundance and price stability, electricity is expected to remain important in the future because it can provide the greatest security for Ontario's energy needs and well being, particularly in the areas of industrial and economic development. Most customers would not like to see economic growth constrained by a limited supply of electricity.

Ontario residents feel secure about the energy outlook for Ontario. They believe there is little likelihood of shortages of any kind of energy in Ontario in the next five to 10 years. Only 25% believe there will be a shortage of any kind. More are inclined to believe there will be energy surpluses (38%). Electricity and natural gas are the two most often mentioned kinds of energy expected to be in surplus in the next 10 years.

Ontario is considered to be extremely well-endowed with hydro electric resources (58%). This appears to be one of the reasons Ontario residents feel so secure about the future supply of electricity.

4.1 Key Findings

- Ontario residents place high priority on the good life and upward mobility.

- Electricity use is expected to increase in the future.

- Ontario residents are positive about the future energy outlook, seeing surpluses not shortages.

- Many residents expect electricity and natural gas to be in surplus in the next 10 years.

- Ontario is well-endowed with hydro electric resources.

5.0 Need for Electricity

Public attitudes and values regarding the Province's need for future electricity supply, customers' future electricity requirements and forecasting are presented in this section.

5.1 Need

The Market Survey indicated that residential, commercial and industrial customers (77% of all respondents) expect Ontario's electricity requirements to grow significantly during the next five years. Seventy nine per cent see business and industry wanting more, with 70% seeing residential customers using somewhat or much more electricity. A majority of consumers (56%) feel that they are using more electricity today than five years ago. The expectation and outlook is for continuing steady growth in demand for electricity.

Overall, most participants in the Regional Consultation meetings thought there would be a need for more electricity in the future. The majority, 65%, felt that Ontario would fall short of its electricity needs if Ontario Hydro did not plan for growth over the next 10-15 years.

Provincial organizations made the following comments on the need for increased electricity supply:

- Electricity is quite literally the life-blood of Canada's economy.... Electricity intensity in the economy is not likely to diminish in the future....we anticipate an increased level of electrification. (Canadian Electrical Association)

- We believe that Ontario's electricity system should be planned to be able to accommodate economic growth of 3-4% for the next decade at least, but with sufficient flexibility to adjust to a changing future. (Ontario Chamber of Commerce)

5.2 Forecasting

Forecasts of electricity load growth play an important part in the planning process. The consultation programs and the market survey provided a range of comments on Ontario Hydro's load forecasting ability, the appropriateness of Hydro's proposed forecast and the pros and cons of over versus under-supply of electrical energy.

Criticism of Hydro's forecasting from provincial organizations included the following:

- The past policies and forecasting growth rates have left the agriculture industry feeling less than optimistic about Hydro's ability to accurately forecast future growth rates (Ontario

Federation of Agriculture).

While some submissions point to overestimates in the past and assume that overestimates will continue in the future, other submissions claim that the Ontario Hydro response to overestimating in the past will be a tendency to underestimate in the future. Examples include:

. We conclude...that Hydro's forecast growth rates, particularly when applied to peak load, are very conservative and are now in a cycle of being on the low side following many years of external criticism of forecasts based on too optimistic a view of the Ontario economy. (Canadian Nuclear Association).

. It is our position that all of us, including AMPCO, have been preoccupied with looking backward at the high surplus just two and three years ago, instead of looking forward (Association of Major Power Consumers).

Other submissions emphasized the uncertainties and the difficulties of planning to meet them:

. The uncertainty induced by variable demand patterns due to economic recession, the oil shock, and changing world economic conditions, have shaken public confidence in the industry unduly (Canadian Electrical Association).

. ...increase is at least as likely as decrease...History clearly shows that one statement can be made with confidence about a forecast: It will turn out to be wrong. (Canadian Nuclear Society).

. The future is, by definition, uncertain. It is not possible to predict with confidence specific demand levels for the future electricity usage. There are two main sources of uncertainty: the amount of future economic growth in the province, and the role of energy conservation (Ontario Chamber of Commerce).

Many organizations felt that the uncertainty surrounding future electricity needs should be met by a flexible mix of energy sources and generating station sizes.

Participants in the Regional Consultation program were asked about the need for more electricity in the future and whether Ontario Hydro's estimate of 2.5% electricity growth was accurate. Although 44% of the Regional respondents felt that Ontario Hydro's estimate of 2.5% electricity growth per year was "about right", 21% felt that the estimate was too low and 9% felt it was too high.

5.3 <u>Surplus versus Shortages</u>

Market survey results indicated that some excess generating capacity is

viewed positively because of the insurance it provides in case demand for power grows faster than expected. Ontario residents are less concerned about the upward pressure on rates from some excess capacity.

Provincial organizations expressed a variety of views on the adequacy of future electricity supply and the desirability of surplus or shortage. Industry associations see shortage as damaging to the economy. Examples of this are:

. Over supply has proved profitable over the last ten years. Under-supply would have severe economic repercussions for the Ontario economy (Canadian Nuclear Association).

. Even if Darlington is completed on its current schedule and if all of Ontario Hydro's "reasonably assured" potential additional contributions to Ontario's power requirements are implemented by the year 2000, AMPCO is still very concerned about Hydro's supply capabilities by the late 1990's (Association of Major Power Consumers.)

The interests of domestic consumers in an assured supply were described by the Consumers' Association of Canada which said:

. Because of the multiple uses of electric energy in the modern home -- lighting, cooking, refrigeration, fans and pumps for heating systems, space heating itself, motors for many labour-saving appliances -- the question of an assured supply is of vital importance for consumers. The modern household would be greatly disrupted if electricity supplies become inadequate.

A different view was expressed by the Sierra Club of Ontario:

. ..."power shortages" are seen as a terrible thing to be avoided, and an automatic cause of loss of jobs. On the contrary, a general Hydro policy of generating SHORTFALL rather than surplus could create exactly the public attitude we need...one of necessary conservation...Nor is it true that power shortages necessarily cause loss of jobs. Some jobs would be affected, but more jobs might be created than lost...since shortfalls of hydro generation would stimulate whole new industries...new designs of energy-saving appliances, new alternative sources, etc. (Sierra Club of Ontario)

5.4 Key Findings

. The Province's electricity requirements are expected to increase during the next 10-15 years.

. Ontario Hydro's electrical planning for a range of 1% to 4%, with 2.6% as the most probable rate, appears to be appropriate given the uncertainties of forecasting.

- Public preference appears to favour a planning process that errs in favour of surplus generating capacity rather than shortages.

6.0 Customer Priorities

This section summarizes findings on 14 priorities most frequently expressed by participants as important considerations in Hydro's planning to meet future energy needs.

6.1 Reliability of Supply

A reliable supply of electricity is identified by participants as one of the most important priorities for Ontario Hydro. Reliability is seen as a continuous supply of electricity with quick restoration of outages.

Market Survey respondents ranked reliability of supply as number one when asked to indicate how important each of a number of different factors should be in guiding Ontario Hydro's planning.

Provincial organizations representing industry stressed the importance of reliability. The Association of Major Power Consumers in Ontario gave "a reliable supply of electricity" as a primary objective and said that "to guarantee future real growth in this province, we must have reliability of service." Other comments on industrial needs for a reliable supply included:

- In our industry it is of paramount importance that a reliable power supply be maintained. Power outages of even a few minutes duration could lead to process upsets which take hours to rectify (Association of Canadian Distillers).

- We believe that Canada's economic future will depend on its ability to adjust to the competitive challenges of a world market-place...A reliable and reasonably-priced supply of electricity will be a significant advantage in this regard (Canadian Electrical Association).

The Motor Vehicle Manufacturers' Association says that it needs "reliable electric power in the necessary volumes," and the Ontario Mining Association expresses "the need for an economical reliable electrical supply."

Many regional consultation participants also stressed the importance of a reliable supply of power, particularly those representing industry. At the Port Hope, Alliston and Timmins meetings, industrial representatives talked of the effect of the loss of electricity for short periods of time. A representative from the new Alliston Honda plant stated it would take half an hour to start up the plant as a result of the loss of electricity for half a minute. Many machines would require repair and Honda would have to scrap 20-30 car bodies. Some Port Hope representatives stated Hydro should not be

moving to a U.S. style of electrical system because costs and reliability concerns would have a major impact on the steel industry.

A Port Hope resident indicated that a reliable supply of electricity was as important as conservation and that Hydro should err by building too much rather than not enough. An Alliston resident stated that the agricultural community relies on electricity, even in the summer. Sudbury and Alliston participants felt that it was more important for industry to have a reliable supply of electricity than homeowners and tenants. A Bracebridge participant, however, noted that people in other countries have learned to live with electricity shortages.

Municipal utility participants indicated that Ontario Hydro has provided good reliable service and must continue to have reliability as the top priority.

6.2 Reasonable Rates

Keeping rates reasonable ranks as an important priority in the opinion of most publics.

Market Survey participants ranked keeping electricity rates as low as possible as tied with environment as the number two priority for Hydro.

Survey results indicated that 49% of the respondents see electricity costs rising at the same rate as natural gas. Fifty-eight per cent see electricity rates rising at the same rate as inflation. Residential, commercial and industrial customers indicated that they expect electricity rates to increase at a forecast rate of 5.8% per year for the next five years.

The United Church of Canada maintained that Ontario Hydro's major responsibility was to "meet the needs of Ontario citizens for electricity, and to supply it at least cost." The United Church went on to say that "if, as Ontario Hydro likes to boast, Ontario rates are among the lowest anywhere, then perhaps this helps explain why Canadians are the second largest consumers of electricity per capita anywhere in the world."

The United Church also said that "the rates are so low as to encourage waste," that rates can be influenced by "creative accounting", and that "the average revenue per kilowatt hour is too low to recover the costs of generating and distributing electricity." In discussing rates, the United Church distinguished between poor residential customers, rich residential customers and corporations. They said that "Corporations are NOT people but only legal entities" and "when these companies threaten to go bankrupt and reduce the number of jobs in the community because of an infinitesimal rise in their costs, we can only smile. They still have the option of raising prices."

Submissions from industry had a different emphasis:

. ...rising energy costs and an unpredictable rate structure can jeopardize employment, production and future growth in all industries. These factors also hurt a company's ability to compete in world markets. It cannot arbitrarily raise its prices to cover a rate increase. (Association of Major Power Consumers)

. Naturally, the importance of low-cost electricity to individual companies varies dramatically, depending on whether they are energy intensive or not...A reliable and reasonably-priced supply of electricity at the lowest reasonable cost consistent with societal values regarding the preservation of the environment...(Canadian Electrical Association).

. Considerations...include...Ontario Hydro's costs and prices as an element of Ontario's ability to attract new and retain current investment (Motor Vehicle Manufacturers' Association).

. ...much of Ontario mineral production is exported with prices being set on world markets that are totally unresponsive to the Canadian domestic scene. As a result, mining companies are unable to control prices and must control costs..."electrical price increases be kept to the absolute minimum." (Ontario Mining Association)

Other comments on rates and costs include the following:

. The old answer has always been "abundant, cheap electricity"...we would be prudent to substitute "enough" for "abundant" and "fairly priced" for "cheap" (Foodland Hydro Committee).

. We...desire that the domestic consumer get the cheapest electricity possible...Some big industrial users of electricity are not paying their rightful share under the present system (Ontario Federation of Labour).

. The Sierra Club proposes...a pricing policy which discourages increased consumption by industries -- make power more expensive, not cheaper, the more that is consumed. (Sierra Club)

Regional Consultation participants spent less time than expected discussing rates. Most of the support for lower rates came from business and industry representatiaves. A participant in Timmins stated that high electricity prices have a negative impact on employment, particularly in the mining industry which requires lower energy costs to remain competitive in world markets. Hydro, however, should give incentives to industries who swing their operation to off-peak periods.

Overall, a strong case was made by most of the industry representatives for no change in the status quo. A few Barrie participants for example, stated it was important to keep rates low to attract industry. One participant stated,

> "Rates do provide a significant competitive advantage to attract foreign investment. And, low electricity rates help Ontario compete with other Provinces."

Moderate support was given by regional participants for higher rates to achieve other purposes such as alternative energy research or environmental protection. There was disagreement with the notion of keeping rates low if there was risk of other negative effects. Several participants suggested increasing rates to avoid nuclear energy and for a clean environment. Some Barrie participants also stated that increasing prices would stimulate conservation while gradually bringing prices in line with the price of purchasing hydraulic electricity from Quebec.

With respect to changes in Hydro's rate structure, opinion was mixed regarding whether the same rate should be charged for all types of customers no matter where they live. For example, participants at the Atikokan meeting suggested that, to stimulate economic development in the north, there might be merit in having an independent northern electricity rate.

Among municipal utility representatives, concern was expressed regarding the need for stability in the rate structure and the importance of low rates to industrial competitiveness.

6.3 Protect the Environment

The environmental effects of the production, transmission, and use of electrical energy are a priority concern of almost all publics. Market Survey results indicate that minimizing pollution or negative effects of the environment was tied with reasonable rates as the Corporation's second priority objective.

Provincial organizations participants underscore this expression of importance:

- While we do consider the cost of power to the consumer of major import, we also feel that it is equally important that the means of generating electricity be such that it does not impart damage to the environment (Association of Canadian Distillers).

- Land, animal life, and plant life should be disturbed only to the extent that ecological systems can continue to function well. (United Mennonite Churches)

- Policy decisions suffer today from the unnatural separation of economy and ecology, with the latter albeit ignored.... (Operation Clean Niagara)

- ...good corporate citizens should do what they reasonably can to minimize damage to the environment in their area of operations. (Municipal Electric Association)

Concern for the environment was strong at all regional meetings. At the Port Hope meeting, it was suggested that Hydro shouldn't increase the supply of power if it meant social and environmental costs. Concern for the environment extended to a concern over the direction of society. Some participants were disturbed by the impacts of industrial expansion and the lack of environmental stewardship. The view was expressed in the Port Hope and London meetings that the economic system should not be based on the premise of excessive consumption.

6.4 Promote Wise and Efficient Use

Market Survey results suggest that the Ontario resident views conservation as a worthwhile value as long as conservation is defined as using resources in a wise, efficient and not a wasteful manner. However, when conservation is defined as frugality, doing without, or denying attainment of the good life and the comfort conveniences that go with it, it is rejected as a value. A similar emphasis was evident in a number of the provincial organizations briefs and in comments from regional and municipal utility representatives.

Comments by provincial organizations included:

- Improvements in efficiency offer us a major opportunity to make our current facilities serve us far longer. Both Ontario Hydro and the Ontario Government should play an active role in ensuring that new investment across our economy is in the energy efficient appliances , equipment and processes. Targets need to be set and incentives need to be developed. (Foodland Hydro Committee)

Many Regional participants also supported the emphasis on energy efficiency saying it would be in long term interests of Hydro to encourage the development of more energy efficient equipment.

Municipal Utilities representatives indicated conservation programs should be attractive to municipal utilities as well as Hydro. All utilities must have a major role in the conservation efforts if they are to be successful. Some felt that even though Hydro had no specific conservation program it was currently promoting the wise and wide use of electricity. One participant asked who's job energy conservation was, Ontario Hydro's or the Government's.

6.5 Flexibility

Flexibility was an apparent theme in the comments of the participants. Typical viewpoints expressed are as follows.

- In planning for the future energy needs of Ontario, flexibility must be

the key to its success. Since it is virtually impossible, in this rapidly changing world, to forecast the degree of growth ten years from now, a variety of options is required which will suit the most likely range of probabilities. (Federation of Ontario Cottagers Associations)

- The key to planning is not accuracy, which is unachieveable, but flexibility to respond to the unexpected. (Canadian Nuclear Society)

6.6 Diversity of Resources

Many participants suggested that Hydro should investigate a broad range of options which will use a diversity of resources. The following comments from three provincial organizations typify this suggestion:

- Ontario has a wide range of basic supply options open to it and will likely continue to benefit from using a diversity of input resources including hydraulic, nuclear, coal, and, perhaps, increasingly, co-generation and micro-hydro. Alternative technologies, including solar, wind, biomass, geothermal and the like, depend on the inherent economics of each application. (Canadian Electrical Association)

- All forms of energy must be investigated as to their feasibility and risks -- coal, tar sands, frontier gas and oil, and nuclear. Renewable energy sources such as solar, wind, biomass, hydrogen and gasohol must all be given priority in research and development. (Motor Vehicle Manufacturers' Association)

- We must recognize that while there are risks associated with all forms of energy, the greatest risk of all and the height of irresponsiblity would be the premature and unsubstantiated rejection of any alternative. (Ontario Federation of Labour)

6.7 Contribute to the Economy

There are a number of areas where participants feel that Hydro has had both beneficial and negative impacts on the economy. Examples of provincial organization's comments regarding Hydro's contribution to the economy are as follows:

- In a province lacking its own supply of hydro-carbons, homegrown electricity at prices competitive with imported energy sources will continue to be the main engine of the Ontario economy while at the same time supporting growth in the economy and providing jobs in Ontario (Canadian Nuclear Association)

- Electricity has played a unique role since the beginning of this century on Ontario's economic growth and development... Its oil and natural gas bill of over $11 billion per year makes the province's economy extremely vulnerable to price and supply conditions over with it has little control. Increased electricity consumption in the Province reduces the dependence on oil and natural gas (Electrical and

Electronic Manufacturers Association.)

6.8 Minimize Borrowings and Debt

Ontario Hydro's debt position is of concern to the various public groups involved in the consultation program. The following are examples of concerns expressed by provincial organizations participants:

- Debt reduction must also be high on the priority list for Ontario Hydro and part of the conservation effort may be met by an increase in rates to cover some of the cost of debt reduction. (Ontario Cattlemen's Association)

- ...we recommend that profits from export should be applied to reducing Hydro's debt and/or geared into the system of paying for, or at least part of, new facilities before they produce power. (Ontario Federation of Agriculture)

- It clearly is cheaper, up to a significant point, to reduce existing consumption, than to build new generating capacity...and the "cheaper" must be calculated not only to include the initial alternative cost of new generating facility, but also the accumulated interest costs of financing it over many years.

Concern about Hydro's debt was more widespread among regional participants many of whom stated that debt is an important consideration in establishing the tradeoffs. On the questionnaire (83%) felt Ontario Hydro should choose options which reduce the amount of borrowing and debt assumed by Ontario Hydro. This is consistent with the view held by many participants, that it would be imprudent to make a large investment with a long term payoff without trying other smaller scale options first.

Some municipal utility participants felt that Ontario Hydro should aspire to a debt: equity ratio similar to that of municipalities and would support higher rates to reduce the debt. Others expressed concern about the Province's guarantee of Hydro's debt and its impact on borrowing rates.

The Market Survey results suggest efforts by Hydro to constrain further increases in the amount of borrowings and debt assumed is ranked number six of eight corporate priorities for Hydro.

6.9 Minimize Social and Land Use Impacts

Concerns about major transmission system expansion of Hydro's facilities included comments about environmental effects and the negative social impacts on the affected landowners and adjacent communities.

Comments from provincial organizations on the interests of owners of agricultural lands and woodlands affected by transmission lines included the following:

- Where generation and loads are far apart major transmission lines may cut across agricultural land. Every effort should be made to minimize the impacts by careful routing, design and construction practices. (Foodland Hydro Committee)

- Transmission corridors have always been a nuisance to farmers, but at the same time, we realize they are needed to move the power from the generation station to the consumer. We feel that hydro should be generated as close as possible to the area where it is being used the greatest. (Ontario Federation of Agriculture)

  When a transmission line is located through a forest the entire corridor removes the land from forestry whereas only the transmission tower sites remove land from agricultural production...The Ontario Professional Foresters Association cannot demand that the forests be avoided at all costs. We are asking that the balance of forest land in relation to other lands at least be maintained. (Ontario Professional Foresters Association)

Concerns on the impact of large generating station projects on small or isolated communities were expressed by the agricultural community:

- Mega projects are inherently boom and bust projects which have a disproportionate impact on local economies. (Foodland Hydro Committee)

- When mega projects are built a long distance from largely populated areas, there is a very high degree of impact. For the short term it may be beneficial but for the long term is it? The completion of the Bruce has had a dramatic effect on the surrounding area whereas other places such as Pickering, because of its geographical location, was never affected in this way. (Ontario Federation of Agriculture)

- ...neither the Ontario government nor Ontario Hydro have addressed the social and economic impact on micro-communitites when construction of mega-projects has been completed, and the highly inflated local economy goes bust. (Ontario Cattlemen's Association)

Regional participants were asked to indicate the importance of social and land use impacts in the follow-up questionnaire. Eighty per cent of the respondents greed that minimizing social and economic impacts upon communities close to energy facilities was important. When asked about minimizing the construction of transmission lines, 45% of the respondents agreed.

6.10 Public Health and Safety

The importance of public safety is underscored by the participants' preference for options that are seen to reduce the risks to public health and safety. For example, hydraulic generation is seen as much cleaner and safer than coal or nuclear power.

Maximizing public safety in providing for the Province's electricity needs was ranked by Market Survey respondents as the Corporation's number five priority out of eight.

The health and safety effects of different forms of electricity production were commented upon by provincial organizations:

- Energy policy must be assessed in terms of environmental impact and the related health and safety of both workers and the general public. (Ontario Federation of Labour)

- The case against [nuclear energy] may be argued on the basis of...risks to public health and the environment from low and high level radio-active pollution. (Operation Clean (Niagara)]

6.11 Equity and Fairness

The question of "who pays" and "who benefits" evoked a wide range of comments. There are definite differences of perception about what the real benefits and costs are, as well as about how the benefits and costs are shared, and how they should be distributed in the future.

Almost all participants express support for the general principle that all electricity consumers should pay an equitable share of the costs. Concern was also expressed by many participants that demand management initiatives must be fair to different types of customers, regions, and to participants and non-participants in the programs. However, some of the comments suggest some inconsistency about this basic principle. For example, there is some support for Hydro offering rate-based incentives to create jobs, stimulate the economy, and/or achieve conservation targets.

Comments by organizations on planning, pricing and rate structures included:

- We need an energy policy geared to attaining self-sufficiency and assuring the provision of adequate supplies of energy at prices consumers can afford. Such a policy must be equitable to all regions, individuals and future generations. (Ontario Federation of Labour)

- the poor may pay 7 cents/kWh or more, and the rich may pay 5 cents/kWh or less...industry and commerce may enjoy effective rates which are lower still than those of rich residential customers. This is surely unjust. (United Church of Canada)

Justice, or fairness, was stressed by others also:

- [AMPCO] "works towards establishing fair and reasonable electricity rates for the corporations it represents...[rate increases] must be based on...stability, efficiency and fairness." (Association of Major Power Consumers)

- The consistent dominant attitude of the utilities has been centered on

the concepts of fairness and sharing. (Municipal Electrical Association)

- The business community requires assurances that future electricity pricing will also be fair. (Ontario Chamber of Commerce)

Representatives of rural and agricultural communities spoke of inequities in the sharing of costs and benefits among rural and urban customers:

- When we drive to a city at night we cannot help wondering why the electrical rate from Ontario Hydro to municipal utilities should be so much lower than to agricultural communities. For example, what percentage of the city energy consumption is energy efficient consumption? Why should we pay for their waste? (Ontario Cattlemen's Association)

- Time of use rate structures may apply in many consumer cases but will likely discriminate against the livestock producer. We can no longer accept paying a higher rate for hydro than other consumers!...Crown corporations were set up to equalize cost and service to everyone, but when it comes to hydro, the farmers have to put up with corridors going through their farms as well as pay more for it than our urban consumers. (Ontario Federation of Agriculture)

- If the rural community seems less willing to accept the debris of the industrial society of which it is a part it may be a reaction to the logic which says "put the undesirable things where they will affect the least number of people." This means that the rural community gets the waste dumps, the risky generators, the heavy water plants, the transformer sites, the transmission lines. Experiences from the past 15 years suggest that generation, loads and transmission must be considered together. Smaller scale projects tend to have a closer link between the "costs" and the "benefits" which may be helpful in getting co-operation and approvals. (Foodland Hydro Committee)

6.12 Mandatory versus Voluntary Programs

In general, most participants express a preference for options that result in the least lifestyle changes for the individual. Most consumers want to make choices about their electricity use, rather than have mandatory changes in energy use.

The Consumers Association of Canada stressed the importance of maintaining freedom of choice for the consumer:

- Consumers should be free to decide how they use electric energy, when they use it and how much they use. However, consumers should be informed or educated relative to the efficient use of electricity and if practical, be provided with rate incentives to use power at off-peak times...We would like to learn more....before Ontario Hydro introduces mandatory changes in this regard. (Consumers Association of Canada)

The Municipal Electric Association says that "demand options should not be mandated for customers."

6.13 Energy Self Sufficiency

Many participants feel Hydro should continue to rely on indigenous energy sources to ensure a secure energy supply and to create and maintain jobs in the Province.

Some provincial organizations expressed views about the role of indigenous fuels for generating electricity:

- [AMPCO] supports a nuclear program because uranium is an indigenous fuel that is virtually inexhaustible. (Association of Major Power Consumers)

- Ontario is fortunate to have developed a highly efficient nuclear industry which provides base load power at attractive costs, supplementing that available from hydro resources and reducing dependency on imported fossil fuel inputs. (Canadian Electrical Association)

Market Survey results suggest that Ontario residents are reluctant to see the Province become too dependent on buying electrical power. Overall sentiment appears to favour building new generating capacity in Ontario rather than buying power if the costs are the same. If there is a clear cost advantage to buying, support increases for this option.

Some municipal utility representatives suggested that Hydro should not rely on other provinces for power. Another suggested that power should be purchased if it is less expensive but the purchase should not be at the expense of jobs in Ontario.

Some regional participants suggest the need for an integrated federal policy with more interprovincial exchanges of energy and better co-ordination with other energy supplies such as natural gas.

6.14 Exports

Electricity exports were discussed at both the regional and municipal utility consultation meetings. In the Hamilton, Atikokan and Winchester meetings, comments were expressed that Ontario Hydro could, "...export on a long term basis if it would save Ontario residents money." Overall, however, participants thought that Ontario Hydro should not be exporting to the U.S. during times of peak electrical usage. Participants thought this causes the peak to be higher, risks reliability and causes potential environmental damage. At a number of meetings, people thought it would be quite acceptable for Ontario Hydro to discontinue electricity exports to the U.S. if this could forestall the construction of new sources of electrical generation. Concern was also expressed about the building of new transmission lines to facilitate long term exports.

Some municipal utility representatives felt that export sales keep electricity rates down for Ontario consumers. A utility representative suggested that export power should be interrupted if generating units or transmission lines failed.

6.15 Key Findings

- A reliable supply of electricity receives widespread support as an important Hydro priority.
- Keeping rates reasonable is seen as an important objective.
- Selecting options that minimize environmental damage has general public support.
- Hydro should encourage consumers to use electricity wisely and efficiently.
- Participants favour a strategy that is flexible -- that is one that is responsive to different scenarios and unforeseen events.
- A strategy that uses a diversity of resources (fuels) is preferred by most participants.
- Options that contribute to the economy of the Province are preferred.
- Hydro borrowing and debt should be minimized.
- Options that minimize social and land use impacts are preferred.
- Public safety should be maximized.
- Hydro's rate structure and demand management programs should ensure equity/fairness for all electricity consumers.
- Options that result in the least lifestyle adjustments are favoured.
- Many participants feel Hydro should rely on indigenous energy sources.
- Public support for electricity exports is mixed.

7.0 ONTARIO HYDRO'S ROLE

What should Hydro's role be in meeting future electrical energy needs? Should Hydro be involved in the economic initiatives of the Federal and Provincial Government? Should Hydro take a lead role in demand management? These questions received a wide range of responses.

Hydro's role is widely seen as being more than that of a utility which produces electricity. The public sees Hydro as a company owned by the people of the Province which is a marketer and supplier of electricity, a

contributor to the Provincial economy, and a competitor with other energy sources such as natural gas. In addition Hydro is expected to perform its activities in an efficient, environmentally and socially responsible manner.

7.1 Planning

The Market Survey asked respondents how much influence Hydro, the provincial government, the consumer, business and industry and environmental groups should have in planning how the Province's future electricity needs are met. Results suggest that Ontario residents would prefer to see a broadly based involvement of key special interest groups. Most, however, appear to want Ontario Hydro to exercise the most influence over the planning process with the provincial government and the consumer being the next most influential bodies. This support is consistent with other survey data in which Hydro is seen as having broad mandate that goes beyond being a supplier and marketer of electricity.

The Association of Conservation Authorities of Ontario recommended:

> participation in a Federal/Provincial co-ordinated approach to energy planning to ensure a healthy and reliable mix of energy sources. Such participation should assist Ontario Hydro in determining its role as simply a service component of the energy network, or as a promoter of economic development in Ontario.

Regional participants generally felt that Hydro should take the lead role in electricity planning. However, a Sudbury participant suggested the need for a co-ordinating provincial energy agency.

Some Hamilton participants stated that the options with long planning horizons will inevitably present problems for Ontario Hydro. Because of the uncertainty of forecasts and the possibility of the technology to meet the need becoming out-of-date, Ontario Hydro should be trying to compress the planning horizon.

7.2 Economic Development

There was a measure of agreement among industry and labour associations regarding Ontario Hydro's role in the economic development of the province. The role of electrical utilities in the provincial economy in the past was elaborated on by the Canadian Electrical Association:

- The importance of electric utilities as an instrument of provincial economic policy has long been recognized. The growth of the supply infrastructure has provided opportunities for stimulating employment through direct construction jobs and through advantageously-priced power to industry. Of fundamental importance is the longer-term, on-going benefit of a well-developed, low-cost electricity supply system which can meet the future needs of Canadian business and industry.

With respect to energy and economic growth the Federation of Labour said:

- If we are to grow as a modern industrial nation, create employment for a growing labour force, increase productivity and provide a rising standard of living for our people, we must have readily available sources of energy at reasonable prices.

In a contrasting view, Operation Clean (Niagara) said:

- From our limited involvement, we have observed that Ontario Hydro persists in limiting its view of its mandate to the exponential expansion of a centralized electricity generating and distributing monopoly. Exponential growth in nature is known only as cancer. It leads to the destruction of the organism that is its host, and to the cancerous organism itself. Exponential growth as an economic objective is not exempt from the same laws of nature, since economic activity takes place within the bounds of the ecology of the planet.

A number of organizations feel that Hydro should not be used as an instrument of economic development. For example, the Federation of Ontario Cottagers' Association said, "We firmly believe that the role of Ontario Hydro should be to supply the necessary electrical energy at the lowest practical cost and not as a tool to create employment and stimulate economic development."

The Consumers' Association of Canada suggests that Ontario Hydro "should ensure adequate and reliable supplies of electric energy" in order to "assist and encourage growth and job creation within the province." But they add:

- We do not believe that Hydro should itself promote such development through expensive advertising programs. Such programs should be left to the industrial and development departments of government.

Regional participants generally felt more strongly that Ontario Hydro should encourage economic development in the Province but under certain conditions. Similarly, many felt that options should be chosen which keep jobs in Ontario. However, this support did not extend to Hydro choosing options that created the greatest number of jobs. Other comments including the following:

- Hydro's role should be to provide reliable cost-effective power. That is a sufficient challenge. Other government agencies are spending enough time and money on economic development.

- Hydro's mandate is to supply energy not jobs. If jobs arise as an offshoot fine, but first priority should be to investigate all energy options, establish energy supply flexibility and minimize costs to the consumer (where possible) and the environment.

- Hydro should encourage 'Economic development' which is not destructive of the environment, which doesn't upset existing social systems and which is essentially energy conservation conscious.

- If we want our province to grow and develop we should look at economic development as a top priority.

- We need jobs and development as much as possible, especially in Northern Ontario. If Ontario Hydro could use some of the resources in Northern Ontario it should, but keep the development close to the raw materials in the north. We have plenty of manpower and a well-educated population.

One Timmins resident summed up local concerns when he said,

> ...a lot of economic growth is related to resource industries in the north-east. Given this, Ontario Hydro should consider decentralized decision making. It is vital that Hydro get into co-generation and Hydro should have a greater role in regional development initiatives in Northern Ontario. Quebec Hydro is being used as a development tool by offering industries lower rates and Ontario Hydro should be doing the same."

While economic development in the north was seen to be a role for Ontario Hydro, a number of participants were careful to express their concerns about the potentially negative effects of economic development. North Bay participants, for example, stated it was important to include all the social and environmental costs when reviewing the economic feasibility of a project. Concern was expressed over the disposal of mine tailings and the long-term health effects of uranium mining.

Market Survey results indicate Ontario Hydro is definitely seen as having a role to play in supporting and promoting the development of the province's economy:

- Seven in ten (70%) think Ontario Hydro should be offering special incentives or discounts on electrical power rates or equipment to try to attract industry to the province or encourage industry and business to expand.

- A majority (57%) say, if need be, Ontario Hydro should offer business subsidized rates to maintain jobs and promote industrial and economic growth in Ontario, as opposed to always charging rates to ensure it recovers its costs of producing electricity (43%).

- Significantly more Ontario residents would approve (55%) than would disapprove (35%) of Ontario Hydro offering companies guaranteed long term electricity rates providing protection against rate increases as an incentive to attract industry to the province.

- Three in four agree strongly (29%) or somewhat (45%) that Ontario Hydro should be prepared to offer low rates to business if this is necessary to maintain jobs and industry in Ontario.

7.3 Electrotechnologies

In their submission, the Electrical and Electronic Manufacturers Association of Canada made a case for enlarging Ontario Hydro's mandate to include the development of programs to encourage the use of electrotechnologies to hold existing industries and attract new industries.

The Canadian Electrical Association said that it believes that "Canada's economic future...will entail the rapid absorption into our economy of state-of-the-art technologies, most of which are electrically driven." They then asked questions concerning electrotechnologies. They said:

> Should utilities provide incentive pricing to encourage the use of such technologies and how will they deal with the criticism that they are encouraging consumption instead of conservation? Should utilities actively participate in the research and development of new, high-efficiency electrotechnologies or should it wait for the market to force the introduction at its own pace? These issues have direct implications for the economy and require government policy which lays out clearly the role of utilities.

7.4 Demand Management

There were mixed opinions on the extent to which Ontario Hydro should be involved in influencing how customers use electricity.

Regional participants offered a variety of comments on Hydro's role in demand management. Bracebridge citizens asked whether Hydro should be deciding what are good and not-so-good uses of electricity. The provision of information, education and encouragement, it was thought, was about as far as Hydro should go. Several people in the Winchester meeting agreed, stating it was not Hydro's duty to decide how people should use electricity. Hydro should give people options rather than legislate conservation. The full extent of concern about Hydro's role was expressed in the Chatham, Sudbury and Kingston meetings where people questioned whether Hydro had a role in the home heating market. Related to this was the widespread criticism of Ontario Hydro's "Stamp Out Cold Feet" television advertisement.

Other regional participants felt that Hydro should be very active in demand management. One North Bay resident, for example, felt it was Hydro's role to bulk purchase new energy saving equipment (meters, heat pumps, light bulbs), or to take over companies that produced energy-saving equipment. Ontario Hydro could act more independently as a quasi-private corporation and bring down the cost of efficient light bulbs and distribute them across the Province.

The Market Survey asked Ontario residents what role they thought Hydro should play as a marketer of electricity. More specifically, they were asked whether they think Hydro should be encouraging conservation of electricity, promoting greater use of electricity, both or neither.

Results indicate that the largest proportion of Ontario residents believe that Ontario Hydro should be involved in both promoting conservation or the more efficient use of electricity and greater use of electricity as an economical, reliable energy source. Few believe that Ontario Hydro's marketing efforts should be aimed exclusively at promoting conservation or exclusively at encouraging greater use of electricity.

Results suggest that Ontario residents want Ontario Hydro to compete aggressively in the energy marketplace and promote electricity for applications for which it is well suited. They feel Ontario Hydro should aggressively market electricity in competition with oil and natural gas companies for those applications for which electricity makes sense as an alternative to other fuels.

The Association of Conservation Authorities of Ontario suggested consideration of a "high profile conservation education program" which includes "forecasts of consequences that could develop if customers don't adopt conservation measures". They also suggested the development of "incentives for non-peak load use" to alter customer use patterns.

The Sierra Club listed pricing policies which could be used to reduce customer use of electricity. These included tax incentives to encourage the design of energy efficient buildings and the manufacture of energy efficient appliances; increased prices for electricity; changes in rate structure; special peak load pricing; and the imposition of taxes on electricity sales, on appliance sales, on incandescent lamps and on peak loads.

In contrast , the Municipal Electric Association says that "demand options should not be mandated for customers." There were many comments on influencing the use of electricity by means of advertising. There was criticism of Hydro's advertising campaigns:

- It is difficult for us to understand why Ontario Hydro continues to promote increased use of electrical energy with expensive advertisements such as "Stamp Out Cold Feet". Hydro's advertising policy should be informative and not sales oriented (Ontario Cattlemen's Association).

- Hydro is spending millions exhorting us to use more electricity, firstly through "go electric" and currently with "Stamp Out Cold Feet" advertising in contradiction with their lip service to conservation of energy (Ontario Federation of Labour).

- Hydro should stop advertising to sell electricity and should promote conservation. (Ontario Federation of Agriculture)

- Our opinion is that meeting the needs of citizens is one thing, but inducing inappropriate wants is another. Much of Ontario Hydro's present advertising does just that. (United Church of Canada)

Advertising and marketing can serve different objectives, and are seen

differently by differing interest groups. The Canadian Electrical Association said:

- The importance of electricity in almost every aspect of people's lives makes it necessary that utilities explain clearly who they are, what they do and why they do it. The importance of this communications role for utilities is sometimes not appreciated and certainly should not be viewed as an undue opportunity to influence consumption patterns. Electric utilities must be free to compete in the information market place by informing customers of where it is to their advantage to choose electricity.

The Ontario Cattlemen's Association said, "Advertising, focusing on education and research on conservation by the user must be a top priority." There was widespread support for consumer education and advertising conservation rather than consumption.

7.5 Role Changes

As circumstances change, the mandate of Ontario Hydro may also need to be changed. The Canadian Electrical Association said:

- It is appropriate that government should review carefully the mandates that they have provided their utility companies to ensure that those mandates take into account fully the changing circumstances within which the corporations will be operating.

7.6 Key Findings

- Ontario Hydro is seen as a company owned by the people of the Province and a company which is a marketer and supplier of electricity, a contributor to the Provincial economy and a competitor with other energy sources.

- Ontario Hydro should play a key role in planning for future electricity needs, along with the government and consumer.

- A Federal/Provincial co-ordinated approach to energy planning is recommended by some participants.

- Hydro is seen as an instrument of Government economic policy, e.g. industrial development, job creation.

- Support exists particularly among business and industry and northern participants for Hydro to offer

  - special incentives or discounts on power rates or equipment for industrial development
  - subsidized rates for business
  - guaranteed long term electricity contracts to companies
  - low rates to maintain jobs and industry in Ontario

- Support exists for Hydro to promote electrotechnologies

- Ontario Hydro should be involved in demand management

- Demand management activities could include

  - consumer education programs with emphasis on efficient use
  - conservation programs offering customers voluntary participation
  - time-of-use rates
  - financial incentives

- There is confusion about, and criticism of, Hydro's dual role as a marketer of electricity and promoter of energy efficiency

- Mandate or role changes, if required, should be made by the Provincial Government

8.0 DECISION-MAKING PROCESSES

The expectations of the public for information and consultation, the approvals process, and trade-offs in the planning process were the subjects of a wide range of comments from program participants.

8.1 Consultation

General support and approval for the consultation process was expressed by participants.

Market Survey participants were not specifically asked about information and consultation expectations in a planning process. However, they were asked how much influence should Hydro, the government, the consumer, business and industry, and environment groups have in planning about how the Province's future electricity needs should be met. Their responses indicate that they would like to see a fairly broad-based involvement of key special interest groups and customers in the planning process.

In general, the comments from Regional participants about consultation early in the planning process were very positive (90% said they were satisfied or very satisfied). Most people thought the meetings had been productive and useful. Many comments were similar to the following:

- Hydro personnel listened well to what participants said and did not react defensively to criticism.

- It gave me insight into Hydro's plans and problems -- good communication session.

- Very good session but it's hard to know how the information will be used.

- Continue to have these public meetings. They are an excellent two way

communications tool towards better development and understanding of our energy needs.

Critical comments from Regional participants dealt more with the meeting format than the concept of consultation. For example, one person said, "...Ontario Hydro should provide more information on tradeoff strategies so that people can have a more informed response." Another comment or said:

. The process left something to be desired. In an open forum such as that we first heard angry, negative explosions, then self-righteous, defensive rebuttals, and then began to address, somewhat rationally, the issues involved with planning and how they might profitably be addressed."

The questionnaire responses indicated that the majority, 86 per cent, of the respondents felt that the citizen participants represented a cross-section of opinion from the region. Those who disagreed suggested that blue collar workers, women, and Indian chiefs from Northern Ontario should be better represented.

Areas that some participants thought were not well-answered involved: the idea of a Provincial energy plan involving natural gas; the different facts presented by Hydro and Energy Probe on tritium; and, "... details on renewable options/amount of budgets being spent/inappropriate borrowing/commitment to nuclear despite clear public disapproval."

Provincial organization representatives voiced similar general approval for the consultation process. Examples of the approval included:

. We approve of Ontario Hydro's efforts to consult with and to obtain the views of responsible outside groups (Consumers' Association of Canada)

. We are pleased with the initiation of the consultation and we support it in principle (Toronto Nuclear Awareness).

. We thank you for providing us with the opportunity to take part in this exercise, which we consider to be a progressive step that should be developed as a permanent component of Ontario Hydro's decision-making procedures (Operation Clean (Niagara)).

. We deeply appreciate the consultation process which has gone on to help Ontario Hydro in recommending and deciding on how future energy needs will be met in Ontario (Mennonite Churches of Ontario).

. ...we are pleased that Ontario Hydro has undertaken a process of consultation at this relatively early stage of the planning process. We recognize your initiative as an important step in the right direction (Canadian Environmental Law Association).

. Public participation in the decision making area of public enterprises is an accepted fact today. The nature and effectiveness of that

participation is an ever evolving process and Ontario Hydro has been at the leading edge for many years. Its efforts should be commended (Municipal Electric Association).

A common criticism from provincial organizations was the lack of time and resources with which to participate. Expressions of this include:

. We regret that we have not been able to [contribute] in a more timely fashion. Limited resources and the priority that we have accorded to preparing a submission to the Ontario Select Committee on Energy have simply made it impossible for us to do so more quickly (Canadian Environmental Law Association).

. Neither time nor funds were available for technical research for this brief (Sierra Club).

. [We need] plenty of time (we did not have enough); succinct information (Hydro did well on this assuming it is only a start); some funding, if we are to get into a serious discussion of technical matters (Conservation Council of Ontario).

Specific recommendations for future consultation were made by Operation Clean (Niagara) including participation in the conceptual stages of planning; participation in the selection of participants, procedures and independent experts; participant funding and sufficient time.

There were statements that fundamental assumptions, and bias, had been built in to the study and consultation program. Operation Clean (Niagara) said:

. We have difficulty making rational assessments of Hydro's specific proposals, because we found that we were constantly questioning many assumptions made in the conceptual stages of these plans.... We discovered as we took part in your process that many conceptual stage assumptions that were fundamental to the directions of Hydro's future plans had been presented to be accepted without question.

The Canadian Environmental Law Association and the Consumers Association of Canada made the following comments about information needs:

. If the Corporation is sincere in soliciting the comments of those with differing views, it is essential that it do so with an open mind and a willingness to reconsider its traditional assumptions...It is difficult to find in your description of a nuclear option, any discussion of the disadvantages of pursuing additional commitments to nuclear generation. The tone is unadulteratedly optimistic. On the other hand, it is hard to find in your description of conservation, even one paragraph that does not include a reminder of some shortcoming, obstacle or other disadvantage associated with this demand option. The bias is apparent. (Canadian Environmental Law Association).

. In order to keep us up to date and perhaps to allow us to comment in

more detail on Hydro's plans and/or proposals, we would need to be supplied with copies of Hydro's long range projections and studies as they are prepared. It would then be possible to attend meetings and exchange views with Hydro officials. (Consumers' Association of Canada)

General comments on the role of consultation were provided by the Canadian Electrical Association:

- It is our perception that special interest groups lobbying for particular points of view, play a valuable role in questioning historical assumptions and in stimulating debate on options and alternatives. It is also clear that many well-funded interest groups are an industry in themselves and are as dedicated to self-preservation as any corporate enterprise. It is clear that a thread of ideological or more self-righteousness frequently intrudes into the evaluation of logical and appropriate alternatives. This is not said out of criticism, but only in recognition that the mind set of narrow interest groups frequently precludes an adequate weighing of the interests of all citizens when making their recommendations. The importance of such groups is that they call into question historical assumptions and stimulate debate. But regulators and utilities should advance cautiously in adopting their suggestions carefully weighing the consequences to all consumers of any particular recommendation. (Canadian Electrical Association)

Municipal utility representatives felt that the general public was not well informed about the demand/supply options. This lack of understanding would therefore require more time, effort and money on Hydro's part to be resolved. The utility representatives support Hydro's efforts to advise and inform the public on what Hydro's problems are and the reasons for the difficulties. One participant stressed the importance of Hydro communicating the need for more electricity to the government and another stressed the importance of consumer education.

One municipal utilities participant expressed the view that groups involved in Hydro's public involvement programs have the right to be heard but they do not have the right to take advantage of the people of Ontario. Another participant found the credence given to interest groups disturbing. This participant felt that despite the costs and their easy solutions, their contributions were taken as valid. One participant suggested Hydro stop listening to the environmentalists and get on with making decisions.

8.2 Approvals Process

The approvals process for Hydro facilities also was subject to a variety of different viewpoints. A Municipal Utility representative suggested that Hydro efforts to involve the public reflected the need to better understand the options, but public input has not helped Hydro build transmission lines.

Most of the Regional participants felt that Ontario Hydro had a role in

finding a better way of working with the citizens affected by transmission lines and other Hydro projects. At the Sarnia and London meetings, the concern was expressed that the current hearings process for the Southwestern Ontario transmission line approval had produced no winners. Many years have passed and much expense has been incurred without a decision. At a number of the meetings, participants expressed concern that the delay in project approval could cost Hydro hundreds of millions of dollars. There was recognition that this represented a significant loss to all people of the Province. However, there was no clear indication whether changing the approval process was the responsibility of Ontario Hydro or the Government of Ontario.

While the hearing process was seen to be potentially expensive and time consuming, many regional participants were, however, still supportive of the idea that all social and environmental concerns be given a fair review. There was overall support for the need for a thorough public review of major decisions.

The United Church sees "the large number of hearings" held on Hydro facilities as evidence that Hydro is out of control. Their brief stated:

> . These [hearings] would not all have been necessary had we had a collective feeling of being in control. If we change Ontario Hydro's mandate so that it has no longer such broad powers, then we can surely save ourselves the energy and expense of many hearings....It would be better, allowing for more public participation, if the municipalities would hold plebiscites (as in former times) to decide when to build or not to build. (United Church of Canada)

A different view of hearings and of public participation is given by the Municipal Electric Association which said:

> Recall that Ontario Hydro does not operate in a vacuum. In addition to the more obvious responsibilities of Hydro to the Ministry of Energy, regular public hearings, special route hearings, select committee hearings, and the Hydro Board itself, here is another less obvious but ongoing interest group. This group is the 1,300 elected or appointed utility commissioners and their management staff, representing more than 320 municipalities in the Province. These people are dedicated to the broad mandate of Hydro in Ontario and they have a vital interest in the directions Ontario Hydro takes to accomplish its part of that mandate. They express that interest to Hydro through our association by resolutions arising from regular district and provincial meetings and by on-going discussions with and representations to, the Ontario Hydro Board and its staff. In today's environment Ontario Hydro could be characterized as operating in a glass house -- certainly not in a vacuum.

8.3 Trade-offs

Provincial Organizations were asked how trade-offs should be made in

electricity planning.

These priorities result, among other things, in AMPCO supporting Hydro's nuclear program. The Association of Major Power Consumers in Ontario see priorities as being built into an organization's objectives. Their primary objectives are to ensure that there is a reliable supply of electricity available at stable and competitive rates. (These priorities result, among other things, in AMPCO supporting Hydro's nuclear program.) On the other hand, Toronto Nuclear Awareness campaigns for a Nuclear-Free Ontario, and this objective is consistent with the case it makes for the "immediate cancellation of the Darlington Nuclear Generating Station".

The Canadian Electrical Association emphasizes "the production and distribution of electricity at the lowest, reasonable cost consistent with societal values regarding the preservation of the environment, but sees "a great danger in overlaying a set of moral priorities" on the selection of appropriate supply alternatives.

The Motor Vehicle Manufacturers' Association discusses costs and prices, adequate supplies, environmental protection, and resource conservation. It says:

- Trade-offs amongst the above criteria will have to be settled by ensuring broad awareness of the issues, consultation with customers, comprehensive but adjustable research, and a flexible system.

The Ontario Federation of Labour does not believe that energy choices, environmental control, and jobs are not incompatible.

- While our first duty is to protect the jobs of workers, we also have a responsibility to society as a whole. But we refuse to be conned by government or industry over the need for trade-offs between energy choices or environmental control and jobs. We believe that alternate and renewable sources of energy can generate new employment opportunities while respecting the environment.

The Sierra Club of Ontario is quite specific about its priorities. It says, "We must decide first, to preserve our ecology, and then, see what amounts of hydro we can manage to produce, not the other way around."

The Consumers' Association of Canada says that "trade-offs...should be based on economies and common sense," and gives examples. They conclude that "...careful judgment and common sense will be necessary to arrive at the appropriate trade-offs."

The submission of the Conference of the United Mennonite Churches of Ontario discusses social harmony, health, the environment, jobs, and other costs. Their underlying beliefs determine their priorities:

1. Social harmony: decisions should be such that they foster people living in harmony and peace.

2. <u>Health</u>: meeting energy needs should contribute to the health needs of all persons.

3. <u>Environment</u>: any disruption in the environment should be only to the extent it allows ecological systems to function well.

4. <u>Jobs</u>: if a greater supply of energy creates more jobs, it should do so only if it meets the above criteria first.

5. <u>Cost</u>: once the above priorities have been taken into consideration, only then is cost relevant. Cheaper energy which violates this will be more expensive in the long run.

A list of priorities, even if agreed upon, does not necessarily make decisions easy. The Mennonite Churches say that their "beliefs and priorities do not make it easy to make decisions...It will be agonizing and difficult to decide if a particular course of action contributes to these ends, both the process of considering them and the desire to make a right decision will contribute to a better world for all of us."

The Ontario Cattlemen's Association say that they "need an acceptable supply of dependable electrical energy at an affordable price," but recognize that in meeting those requirements there are conflicting environmental, social, and technical criteria. The trade-offs will not result in a perfect solution.

The Canadian Electrical Association says that each of the "issues is complex and has ramifications and consequences far beyond the first level of consideration."

Few organizations said how trade-offs should be made, and who should take responsibility for them. The Conservation Council of Ontario addressed this question by saying:

- The trade-offs should generally be made by elected officials (preferably MPPs), on the advice of provincial staff, outside (non-governmental) agencies or, to the extent that decisions can be decentralized relative to local power plants. they can be made by locally elected officials, again with the advice of Hydro and others. Certainly, in substative terms, the trade-offs should err on the side of a comfortable safety margin in provision of power, but only once everything has been done to conserve our natural resource base and environment.

8.4 <u>Key Findings</u>

- There was general support for consultation-activities to date and for future steps in the planning process.

- Consulation needs identified by some participants included:

- participant funding
- hiring of independent experts for public groups
- sufficient time for involvement

- Most participants felt the approvals process is necessary but should be streamlined. There was no consensus on the party having responsibility for this action.

- Trade-off criteria suggested included

  - those discussed in Section 6.0 Customer Priorities
  - common sense
  - broad participation
  - lead role for Hydro with contributions from government, consumers and interest groups.

9.0 DEMAND OPTIONS

Load Shifting

Load shifting alternatives -- controlling demand with devices that shut off electrical appliances and indirect methods such as rate-based incentives were commented upon by many program participants.

Market Survey results indicate that there is widespread resistance to instituting any sort of mandatory measures to shift load, even if it means lower rates. Respondents want such programs to be completely voluntary. However, if financial incentives were offered in support of a load control device program, approximately one quarter of the residential respondents indicate they would participate. Incentives for both load shifting and conservation are discussed further in section.

Market Survey responses from both residential and commercial/industrial consumers show that there is widespread support for Ontario Hydro offering time-of-use rates. However, it appears that people will not support time-of-use rates if the peak rate is perceived as punitive. If consumers feel that peak rates are being pushed higher than they would otherwise be to subsidize discounted rates during off-peak periods, there could be considerable resistance. The study findings suggest that incentives could motivate a significant proportion of residential consumers to shift their electricity consumption patterns to off peak periods, or take steps to make their households more efficient. About 25% of residential consumers say they would be very likely to take advantage of time-of-use rates. The motivating level of incentives to use time of use rates appears to be a rate discount of approximately 25%. Commercial and industrial respondents do not respond as favourably to these incentive programs. Only 12% say they would be "very" or "somewhat" likely to shift their electricity consumption to off-peak hours if time-of-use rates were available. Only 8% say they would be "very" or "somewhat" likely to shift their consumption to off-peak seasons if seasonal rate incentives were available.

Commercial/industrial consumers tend to prefer load control devices that would shut down some equipment in peak periods in return for a rate discount and interruptible rates over other demand options. About one quarter of commercial and industrial consumers would be very or somewhat interested in participating in a program using load control devices.

Provincial organizations comments on load shifting suggest that personal choice, voluntary action and savings to all customers were important evaluation criteria. Examples representing these comments are:

- ...it is suggested that direct load control practices which deny the consumer an appropriate level of personal choice, should be approached with due caution. (Canadian Electrical Association)

- Ontario Hydro should take into account the...development of incentives for non-peak load use to alter customer use patterns. (Association of Conservation Authorities)

- Time-of-use rates should be offered on a voluntary basis rather than being forced on those that might be able to take advantage of them as this is one way that Hydro could manage its demand...The value of interruptible power to the system should also be re-examined. (Ontario Mining Association)

- Time-of-day and time-of-year pricing warrant continued examination and experimentation but any price differential should reflect generation costs rather than some arbitrary penalty price. (Chamber of Commerce)

Some organizations commented on the limitations of load-shifting for large users of electricity:

- On the subject of load management, the major industrials have to a large degree just about maximized their potential. Admittedly, the introduction of time-of-use rates has the potential to take 4% off the peak but this is not a major contribution. (Association of Major Power Consumers)

- In the case of demand options universities have only limited ability to adjust their daily electrical demand profile to avoid prime time-of-use rates. By making a substantial investment in physical plant modifications, part of their loads in high daytime rate periods could be shifted to lower night rate periods...The high interest cost of commercial loans and the risk of not achieving the forecast cost avoidance has caused universities to stay away from borrowing money to implement this work. (Association of University Business Officers)

- Shifting electrical energy consumption of off-peak hours is not particularly appealing, as an opportunity for savings in bottling and maturing will be more than offset by the labour premiums which will be incurred. (Association of Canadian Distillers)

In the Regional meetings across the Province, load shifting and time-of-use rates dominated much of the discussion. Barrie, Atikokan and Hamilton participants, and others supported price incentives and disincentives. The Bell Canada system of telephone off-peak rates was mentioned often. The Hamilton, Atikokan and Winchester meetings gave strongest support for charging more for electricity at peak times. A Bracebridge participant stated it was important for consumers to know their costs of using electricity at peak times, and recommended better meters showing consumption at peak times.

If the time-of-use rates meant Hydro could avoid building new generation it would mean that changing to this rate system had social justification. And, many participants stated they would be willing to make some sacrifices if called on. Time-of-use rates would also have economic justification, as stated by an Atikokan resident, if there was at least a 25 per cent price differential between peak and off-peak hours. There was some concern, though, that the residential customer's shift to electricity use in off-peak times would not be permanent. People would eventually revert back to peaktime use.

Some Atikokan and Hamilton participants however, disagreed with the possible use of time-of-season rates or changing daylight savings time. "...seasonal rates would be difficult to impose for people who live in northern parts of the Province and have shorter days."

There were differences in opinion among homeowners, industry and agriculture. Homeowner seemed more willing to accept time-of-use rates.

Some regional participants in meetings across the Province felt that the burden should fall to industrial customers to shift loads and absorb increases related to a change in time-of-use rates. Other participants felt that time-of-use rates and load shifting should be the responsibility of the commercial and residential user, "...it is probably easier to move residential customers off-peak than industry."

A Port Hope participant representing a major local industry stated that off-peak rates mean workers would often have to work the midnight shift. This would precipitate a major labour dispute and run contrary to the lifestyle and aspirations of most workers. Numerous participants stated that time-of-use rates and higher rates at peak would ultimately mean industry pays more for electricity and this would greatly lessen competitiveness.

Representatives of the agriculture community across the Province felt that they had some ability to take advantage of time-of-use rates. A Barrie participant stated, "farmers could help Hydro with load management since feed mills and some farming operations could occur in off-peak hours." A Winchester participant agreed but added, "...there had to be incentives to move agriculture off-peak. Around $100-$200 per month would be sufficient incentive"... At the Winchester meeting a final remark was made that it was easier for industry and agriculture to move off-peak but "...how do you permanently move a whole society away from current electricity use habits?"

While there was opposition to Hydro turning off water heaters from time to time, numerous participants felt Hydro could do a better job in reducing electricity used at peak times by installing timed and more efficient water heaters. In several meetings, participants suggested that the capacity of residential hot water heaters might be increased and put on timers so that water heating could be done during the night. Some concern was related to the lack of supply of hot water during the day and the cost of the switchover. Barrie participants stated Hydro should research better hot water storage technology. And Hamilton participants said there should be financial incentives for installing more efficient hot water heaters.

A number of utility representatives felt that rate-based incentives for both residential and industrial customers would be appropriate for load shifting. The existence of current off-peak rates for industrial customers was mentioned several times. One participant indicated that a study of 500 customers was underway to assess their reaction to incentive rates. Another representative stressed the importance of municipal utilities having a sense of ownership in whatever program initiatives were pursued. Comments from utilities representatives on load control devices were as follows. A municipal utility representative felt that there is a large up front investment requirement for water heater controls. The 18 utilities currently using water heater controls were mentioned by another participant.

9.2 CONSERVATION

As noted in Section 6.4 Market Survey results suggest that the Ontario residents view conservation positively if it seen as using resources in a wise, efficient and not a wasteful manner. However, when conservation is defined as doing without, there is less support. A similar emphasis was evident in a number of the provincial organizations' briefs and in comments from regional and municipal utility representatives.

Market Survey results indicate that the public has developed an energy conservation consciousness and has made conservation-oriented behaviour changes and will continue to do so in the future. Forty-seven per cent of the respondents say they now practice energy conservation. These conservation trends are expected to continue as 59% say they will buy more energy efficient replacement appliances. Others indicated they would be upgrading their home insulation in the future and expected to reduce the number of electrical product purchases. A significant group of respondents, 54%, however, say they do not plan to reduce their electricity usage or use it more efficiently unless there are appropriate incentives to do so.

Most provincial organizations, regional and municipal utilities representatives expressed support for conservation programs as well. A number of reasons for support were expressed. Many participants supported conservation as they felt it was the responsibility of the people of Ontario to leave energy for future generations and not squander resources. The distinction between energy wants and needs was an important factor.

The perception that fewer environmental impacts are associated with

conservation was suggested by a number of participants. The Nature Conservancy of Canada expressed its view:

> In order to ensure that habitats do not disappear rapidly, the Conservancy favours most strongly the push for further energy conservation, co-generation opportunities, use of new and innovative technologies... (Nature Conservancy of Canada)

Conservation initiatives were perceived by some participants as being more effective and less costly than new generation. The Canadian Electrical Association stated the governing principle of 'lowest reasonable cost' dictates that utilities must address how to better manage the demand side of their business. A municipal utility participant felt that a conservation program would save the equivalent cost of providing generation. Some regional participants felt that a conservation program would mean less debt for Ontario Hydro as the construction program over the last 20 years was seen as being "so highly capital intensive, requiring the borrowing of huge sums from foreign sources." In addition, conservation programs received a high level of support as many participants expressed a perception that there was currently a lot of inefficiencies in the use of electrical energy.

Program participants who were cautious about or opposed to conservation gave their opinions. Some regional participants felt that Ontarians should be allowed to use as much electricity as they want and that strategic conservation simply delays the need for new generation. Regional participants did not want to see conservation initiatives alter the reliability of supply. One Barrie participant suggested that if everyone conserved, there would only be more electricity available to export to the United States. Participants in the London and Timmins meetings felt there was not much more conservation that could be achieved from larger businesses without large capital investment.

Other negative comments on the strategic conservation option seemed to involve the question, "will it work?" Some Winchester and Barrie participants stated that demand management options such as these would only be acceptable if they could be implemented. A Bracebridge participant stated, "...incentives are fine for the individual receiving them, but this subsidization then presents a problem for those not receiving them." A Municipal Utilities representative felt that utilities should provide electricity as the public perceives the need and let market forces dictate the outcome.

Other participants felt that an energy conservation program would result in increased use of electricity. The Ontario Chamber of Commerce said:

> Energy conservation has become and will continue to be good business. We can safely predict that business will be even more efficient in its energy usage in future years than it is currently. However, that may mean more, not less, usage of electricity. For example, in the residential area, heat pumps are more efficient than oil-burning furnaces but clearly some of the savings in oil is offset by increased

electricity usage. Similarly, in business, there are applications where increased efficiency will mean a shift to electricity from alternate fuels.

Participants discussed a number of conservation measures such as conservation information, promotion of improved efficiency, rate structures, etc. Conservation education programs were seen by many organizations as an appropriate option to pursue:

- the development of a meaningful and high profile conservation education program that will result in more efficient use of electricity by Hydro's customers. The education program should include forecasts of consequences that could develop if customers don't adopt conservation measures. (Association of Conservation Authorities)

- The matter of conservation should be actively emphasized and encouraged at every opportunity. Hydro's advertising should go all out to encourage conservation of electricity, in co-operation with the utilities; it should strive to be educational, providing specific information, including costs, to the public. (Federation of Ontario Cottagers' Association)

- Public information on energy conservation must continue...Ontario Hydro's advertising should be educational, not promotional. (Consumers Association of Canada)

Most of the regional participants favoured Hydro increasing its involvement in consumer education. Sarnia residents spoke of the efforts of the natural gas companies to educate through bill stuffers, flyers and promotional advertising. Hamilton, Barrie and Timmins participants stated people should receive information on the payback period of conservation options and the cost of leaving a light on. A Barrie resident, for example, stated, "...the electricity bill should show how much electricity use has been reduced over each year." Numerous participants stated that information about energy conservation should be directed toward the young. Hamilton participants suggested that Hydro try innovative approaches to energy conservation such as energy fairs.

Some organizations felt the emphasis on conservation programs should be to increase energy efficiency:

- Ontario Hydro and general government policy help to stimulate or retard the growth of demand in many ways, ranging from policy on certification of home appliances to policy on Hydro advertising (STAMP OUT COLD FEET), to pricing policy. (Sierra Club)

- Improvements in efficiency offer us a major opportunity to make our current facilities serve us far longer. Both Ontario Hydro and the Ontario Government should play an active role in ensuring that new investment across our economy is in energy efficient appliances, equipment and processes. Targets need to be set and incentives need to

be developed. (Foodland Hydro Committee)

- Ontario Hydro should assist manufacturers in getting the message out to consumers as better equipment is developed and marketed. (Consumers' Association)

Many Regional participants also supported the emphasis on energy efficiency saying it would be in long term interests of Hydro to encourage the development of more energy efficient equipment. At the North Bay, Hamilton and Winchester meetings some participants felt Hydro should be selling or promoting high efficiency light bulbs. Hamilton participants suggested that timed light switches also be installed and a North Bay participant said, "...Hydro could pay part of the cost of installing these [energy saving] lights in residential housing units and end up with a net saving in energy despite the high cost of the bulbs."

Comments of support for rate incentive approaches to conservation were made by regional, municipal utilities and provincial organizations participants. Municipal utilities participants felt that with the proper pricing, customers would find the best way of using electricity economically.

Changes in the declining block rate structure or increasing rates generally were given support by some regional participants, if the change would achieve conservation. A North Bay participant, for example, stated that keeping the rates at or below the rate of inflation would create, "...little incentive for customers to save." Commenting on the block rate structure, an Atikokan participant stated, "...the 'more you use the cheaper it gets,' price structure gives a message to bulk users. Hydro should structure rates to not favour the big users." And, a North Bay participant stated that Hydro should lower the rate for those who lower their electricity usage.

Foodland Hydro Committee felt that in an electrically heated home you could double the rates if through insulation, weatherstripping and better controls you could cut the heat loss in half. Reforming the rate structure would be one part of sending a consistent message with respect to electrical efficiency and conservation.

The Sierra Club expressed the following opinion:

- It has been stated that the price of electricity has no effect on demand. Various research documents reveal this statement to be untrue over the long term, and efforts are usually made by individuals who are more concerned with stabilizing the cost of the monthly electricity bill than with the number of kilowatts consumed. The increase in price therefore generates a conscious effort to turn down the heat, switch off lights, reduce air conditioning and purchase was over the long term -- appliances which are more energy efficient. (Sierra Club)

A different viewpoint was expressed by the Ontario Federation of Labour.

- We believe in conservation. But we do not subscribe to the philosophy

> which maintains that the only way to conserve energy is to put a higher price on it. There has to be a clear distinction made between the careless and wasteful increase in the use of electricity and the legitimate increase in use such as in the expansion of industry.

A number of other suggestions were made by participants on ways to conserve electrical energy. The Ontario Electrical League advocated the "Smart House" concept as a means of energy conservation, utility control of demand load, and safety improvements in the home. A municipal utilities representative also mentioned this approach but was of the opinion that energy efficient homes were not selling as well as had been expected.

Suggestions were made by regional participants that customers should be given money to aid conservation. Atikokan participants suggested Hydro should lend customers money for conservation initiatives and Barrie and Bracebridge participants said homeowners should get a bonus or rebate for reducing consumption. Others disagreed stating this would compensate those who were not conserving now. A brief submitted at the Port Hope meeting noted that in Japan, "...any business which can show an energy saving resulting from R. and D. expenditure is permitted to deduct this expense from taxable income...[the Japanese] work harder to find ways to make people more conservation conscious." Several suggestions were made relating to changes required in civic laws. Some Hamilton participants noted that there might be bylaws to reduce night time billboard advertising. Some participants supported municipalities enacting stricter standards regulating energy efficiency in dwellings.

Market Survey results show that electricity consumers see Hydro playing a key role in conservation programs. The Canadian Electrical Association pointed out the importance of utilities undertaking a strategic role in energy conservation. The Canadian Consumers Association said they rely on Ontario Hydro to provide the technical expertise and to show leadership by being in the forefront of developments in the electric industry. Municipal utilities representatives stressed the importance of conservation programs being attractive to municipal utilities as well as Hydro. All utilities must have some ownership in the conservation efforts if they are to be successful. Some felt that even though Hydro had no specific conservation program it was currently promoting the wise and wide use of electricity. One participant wanted to know whether energy conservation was Ontario Hydro's or the Government's responsiblity.

9.3 INCENTIVES

Market Survey results indicate that the primary motivation for consumers to reduce their energy use is to save money. Most respondents indicated that a 26% incentive on their monthly bill would be required for them to change their consumption habits. Many feel that some energy savings are possible now without any form of incentive. Some 19% of residential respondents and 10% of industrial and commercial consumers feel they can reduce their electricity consumption on their own.

The degree of support for Hydro becoming involved in offering financial incentives to encourage more efficient use of electricity or load shifting appears to be tied directly to the effect that offering such incentives would have on rates. Financial incentives to encourage more efficient use of electricity or load shifting are supported only so long as they do not push rates up. If the effect of offering financial incentives is to push up rates, they are rejected.

9.4 KEY FINDINGS

General Aspects of Demand Management

- Conservation is seen by the public as using resources in a wise and efficient way, not doing with less.
- Support exists for Hydro to offer rate-based and non rate-based incentives to shift load and encourage consumers to use electricity more efficiently.
- These incentives are supported if they are available to all customers and are not seen as increasing rates, punitive and/or mandatory.
- Mandatory initiatives could be offered if they are accompanied by financial incentives.
- Reasons for support include:
  - more effective/less costly
  - responsibility to future generations
  - less environmental impact
  - the U.S., Europe and Japan experiences
  - less capital intensive and incurring less debt
  - addresses current inefficiencies in the use of electricity
- Reasons for opposition include:
  - consumers should decide how they use electricity
  - only delays the need for new generation
  - could have negative impacts on reliability of supply
  - no potential left, most significant savings have already been taken
  - unpredictability/uncertainty

Specific Aspects of Demand Management

Load Shifting

- Rate-based and non rate-based incentives to encourage load shifting identified by the public include:
  - time-of-use rates
  - digital read out equipment
  - timers on hot water heaters
  - change daylight savings time

- improved water heating equipment

. Residential consumers show more support for time-of-use rates than industrial/commercial customers.

Conservation

. The public has developed an energy conservation consciousness and made changes in their electricity consumption habits. These trends are expected to continue.

. Approaches having varying degrees of public support include:

  - consumer education
  - consumers own voluntary action
  - promotion of energy efficient homes -- equipment and appliances
  - financial incentives including rate discount, insulation, grants, appliance rebates
  - change regulations or municipal bylaws to increase energy efficiency standards

Hydro's Role

. Ontario Hydro is seen as having a lead role in the development and implementation of conservation program initiatives. Municipal Utilities wish to participate with Hydro.

10.0 SUPPLY OPTIONS

10.1 Hydraulic:

Hydraulic generation received widespread support from participants. Market Survey results indicate hydro power is the most favoured supply side option for Ontario consumers. Hydraulic power is considered to be in abundant supply, the lowest cost, and the least destructive to the environment.

Provincial organizations participant comments also expressed support for the hydraulic option. Examples are as follows:

. Indigenous hydro-electric generation has been and remains an excellent choice for Ontario, particularly since all of the construction jobs and almost all of the manufacturing jobs are in Ontario. (Canadian Nuclear Association)

. On the supply side, it appears that the potential for further hydraulic generation is rather limited...Nevertheless, every effort should be made to identify and harness the most suitable and economic of these, whether by private enterprise or not, since hydraulic generation is not only a renewable resource but also relatively clean environmentally. The Niagara River stands out as a particularly suitable prospect for further development, in making more efficient use of these waters.

(Federation of Ontario Cottagers Association)

- Since hydraulically generated power should be the most economical and environmentally clean source, then Ontario Hydro should place the development of hydraulic sources highest on its priority list, correlating development with storage capacities whether it be pumped or dammed. (Ontario Cattlemen's Association)

- It would appear desirable to emphasize renewable energy sources such as hydraulic. We understand that essentially all of the significant, developable hydraulic sites in Ontario have already been exploited. If any sites remain undeveloped, even in remote areas, construction there should be carefully considered at this time. (Consumers' Association of Canada)

There were also some comments recommending caution with regard to hydraulic generation from cottagers, conservation and energy associations:

- In considering the hydraulic option, we would hasten to emphasize the serious dangers of daily peaking of hydraulic power plants where severe fluctuations in water levels pose a very serious hazard to those people using the rivers for recreational purposes....In addition, weekly and seasonal fluctuations can be very damaging to fish and wildlife unless steps are taken to identify these problems and the appropriate control measures put in place. (Federation of Ontario Cottagers' Association)

- The Conservancy has concerns with both macro and micro hydro-electric generation in the province of Ontario...we would be quite concerned that private citizens might take the opportunity to make a few extra dollars and start damming up rivers, not knowing what effect it would have in the short or long term. The effect of that could be:

  1. to destroy endangered habitat or species.
  2. to prevent the free use of rivers for water sports, fishing, canoeing, hiking, etc.
  3. to create flow and silt problems and generally disrupting the natural flow of rapidly diminishing river courses in this province.

  Toronto Nuclear Awareness does not want to see another environmental disaster like James Bay in Ontario's north -- the Albany, the Attawapiskat, the Winisk and the Severn should all remain free and wild rivers. We want small, medium, and micro development in the south and near north. (Toronto Nuclear Awareness)

Regional participants also favour the hydraulic option. Timmins participants suggested Hydro should intensify its efforts to construct hydraulic generation. One participant suggested that the longer lifetime of a hydraulic plant when compared to a nuclear plant was a factor in favour of pursuing this option. Several participants suggested that Hydro examine the damming of major rivers such as the St. Clair.

Small hydraulic technology was also mentioned at regional meetings. A Winchester participant suggested that Hydro should be investigating all sources of small hydraulic. A Port Hope participant suggested that a recently developed flow generator be placed at numerous spots along a stream. Most participants felt it was acceptable for Hydro to encourage communities with hydro dams or other energy sources to produce their own electricity.

Many participants say that the current Hydro buy back rate is a disincentive to small hydraulic development. A Timmins participant stated, "The buy back rate is not realistic even though it's almost double what it used to be. Hydro can build very little that can generate power at that level for the price." An Atikokan participant stated, "Ontario Hydro should pay private electricity users the same money as it would pay to produce electricity from a new nuclear unit."

Municipal utility participants were interested in Hydro support and assistance for small hydraulic. Leasing hydro-electric generation rights in Quebec and Manitoba for 50-100 year leases was suggested by a participant.

10.2 Natural Gas

Market Survey results indicated that, without knowing the relative costs of producing electricity from various sources, Ontario residents tend to favour natural gas as the second most desirable conventional option. However, when respondents are made aware of the cost, nuclear is preferred over natural gas. Primary reasons for preferring natural gas generation include its abundant supply; cleanness and low cost. Those respondents that do not support this option expressed concerns about costs and safety.

Regional participants were generally interested in the natural gas option. A Timmins participant argued strongly that Hydro consider natural gas stating, "...there is plenty of cheap natural gas in Western Canada and for Ontario Hydro it has the following advantages: no environmental problems; no inventory is required; there is plenty of it there, and; it has low handling costs."

Natural gas was supported as a substitute for electricity for heating and transportation fuel by Sudbury participants, who stated, "...perhaps it might be wise to use gas, for example, as a heating fuel, while keeping electricity for lights, motors and other equipment that can only be run on electricity." A Bracebridge participant called for the use of natural gas (instead of electricity) where applicable in urban areas. Another point raised by many participants was the concern about natural gas competing with electrical for the same end uses. Participants in Hamilton, Chatham, Winchester and Sudbury also discussed the roles of Hydro and the gas companies and recommended co-ordination in policy and planning for electricity.

10.3 Alternative Energy Technologies

Consultation program participants commented on alternative energy technologies such as wood burning, burning of municipal solid waste, photovoltaics, wind generation, solar power and hydrogen.

Wood Burning

Regional participants in Timmins focussed much discussion on the burning of wood. All participants were aware of the proposed Chapleau wood burning system and most felt it should be tried in the Timmins area. Participants believed there would be both energy produced and social benefits resulting from a labour-intensive wood gathering operation.

Municipal Solid Waste

The second most frequently mentioned source of non-traditional electricity production by Regional participants, was burning municipal solid waste. Participants in Winchester, Kingston, London, Barrie and Port Hope mentioned that generating electricity using municipal solid waste had merit. Most participants recognized that municipalities had increasing difficulty finding sites for garbage disposal. Support continued to be strong even when the notion of higher costs of disposal or less reliable electricity was seen to be a factor. One Winchester representative, for example, said, "...A major developer like Ontario Hydro should be involved in this sort of co-generation." Barrie participants agreed and stated, "...Orangeville is trucking garbage quite far now and is investigating burning garbage. Perhaps if Hydro considered a joint venture it would get a positive response from the municipality."

While there was seen to be a lot of potential in the burning of municipal solid waste, a number of problems were also foreseen. Hamilton participants pointed to the problem of a dump having to be located next to the incinerator. The emissions are often foul smelling, and toxic materials must be successfully removed. Some Sudbury participants also pointed to truck traffic to the facility. The sporadic production of garbage from all but the larger centres was also seen to be a concern.

There were comments both "for" and "against" use of municipal garbage as a fuel from provincial organizations. Comments favouring waste burning included:

- Incinerator plants could and should be developed. Garbage dumps have plagued society since the beginning and incinerator plants could go a long way in cleaning up the environment as well as producing hydro. (Ontario Federation of Agriculture)

- ...the government should "respond to the Porter Commission's recommendation that every effort be made to convert some installations to burn refuse or refuse-derived fuels." (Ontario Federation of Labour)

Comments opposing waste burning included:

- ...the burning of domestic and industrial wastes could easily be a source of air borne PCB's and other toxicants as there may be no way of knowing the constituents of the waste. It is also doubtful that the burning temperatures would even approach that of a rotary kiln whereby

PCB's could be destroyed instead of entering the atmosphere. (Sierra Club)

- Toronto Nuclear Awareness opposes the generation of electricity or heat from municipal solid waste.

Solar and Wind

A variety of comments were made by provincial organizations and Regional representatives on technologies such as solar and wind generation, and photovoltaics. Examples of provincial organizations views include:

- We are skeptical that Ontario Hydro is devoting enough resources to active solar and wind generation. (Toronto Nuclear Awareness)

- Alternative technologies, including solar, wind, biomass, geothermal and the like, depend on the inherent economics of each application. In many instances, private-owned solar systems can contribute to reducing individual requirements for centrally-generated electricity and if the individual feels that it is in his or her best interests, then he or she should go ahead and implement it. But the fundamental principle of maximum benefit to the majority dictates that utilities not be saddled with unrealistic buy back pricing for self-generated electricity. This would not be in the best interests of the citizenry as a whole. (Canadian Electrical Association)

- ...we fully support the research needed to make...wind generation, photovoltaics and solar energy viable energy sources especially in remote areas where conventional fuel sources are very expensive, or where the use of alternative energy sources would obviate the need for long environmentally unacceptable transmission lines. (Sierra Club)

- Alternative sources of electricity such as wind and solar generation should continue to be studied. Their use, however, should remain limited and experimental until such time as their costs come more into line with conventional generation techniques. (Ontario Chamber of Commerce)

Solar power was the second most favoured option when conventional and number of options were considered by Market Survey respondents. Commercial/industrial customers rank the solar option as their third choice. However, hydraulic as first choice leads solar in support by a wide margin. Solar is favoured because it is considered to be low cost, clean and a renewable energy source.

General

In general terms, regional participants saw alternative technology options positively given their perception that significant amounts of

electricity could be provided without the intensive capital and debt implications associated with major generating facilities. There were, however, a number of general concerns. Some participants felt that alternative technologies would not provide reliable electricity. Others were concerned about the price of these technologies. In addition, Hydro was asked about who would own the source of generation and would they produce a reliable supply. A participant in Barrie stated "...for Hydro to rely on customers to produce electricity, it would be unadministerable."

Typical of the views expressed on alternative energy were those of a Chatham resident who said that wind, solar and alternative energy had a large future but, for now, they are expensive and only provide site-specific energy. Where they can provide homes, cottages and remote areas with electricity at lower cost than other means, they are good, but they will provide an insignificant amount of electricity for our overall energy needs.

10.8 NUCLEAR

The nuclear option appears to be the most controversial of the supply alternatives based on the comments received from consultation program participants. Some participants approved of its use, some gave conditional support and others were strongly opposed.

Market Survey results indicate that nuclear power is the second most favoured option from a cost standpoint by commercial/industrial consumers and the fourth most favoured option by residential consumers. Reasons cited for support for nuclear are that it is: cheap, clean, cost-effective, abundant, safe, reliable, proven, environmentally most benign and the energy source of the future. Public safety was the key concern about nuclear. Respondents reasons for rejection included that nuclear plants are too dangerous/unsafe, are not fail safe and pose the problem of nuclear waste.

The following comments in support of the nuclear option were made by provincial organizations:

- Ontario is fortunate to have developed a highly efficient nuclear industry which provides base load power at attractive costs, supplementing that available from hydro resources and reducing dependency on imported fossil fuel inputs. While it remains for consensus to be reached on the long-term waste disposal issue, there is nothing to suggest that effective solutions will not be available when required. (Canadian Electrical Association)

- 94% of the jobs associated with construction and operation of a nuclear plant are in Ontario. Also both Ontario Hydro and the Ontario Ministry of Energy agree that nuclear power has the capability to generate large amounts of electricity safely, dependably and cost-effectively. (Canadian Nuclear Association)

- It also appears that the nuclear option has a significant role in planning for the future since the use of nuclear power plants is fundamental in reducing acid gas emissions from fossil-fuel plants. (Federation of Ontario Cottagers)

Conditional approval of the nuclear option was expressed by some provincial organizations.

- To meet the final electrical needs of the Province after programs of conservation, co-generation, purchase from customer owned facilities, we may have to construct further nuclear stations, however, they should be on a smaller scale adjacent to load demand. (Ontario Cattlemen's Association)

- ...now that the Province has committed itself to nuclear it would be politically difficult to reverse this. While some of the other provinces can rely on fossil fuels...Ontario is not in that position and will have to use existing nuclear power and undeveloped hydraulic potential as a bridge to future energy supplied from renewable and other sources. (Ontario Federation of Labour)

- The Conservancy is not concerned with the generation of nuclear power per se but we certainly are concerned with the mining end of the operation... our concern would be that tailing ponds be located in areas which do not threaten or destroy endangered habitat or species. (Nature Conservancy of Canada)

- Most Sierra Club members in Canada do not regard a "melt down" situation a potential problem in nuclear power generation. The same members however, are greatly concerned about the disposal of radioactive wastes. (Sierra Club)

Other provincial organizations expressed their opposition to nuclear energy. Toronto Nuclear Awareness said, "We oppose nuclear power in favour of soft energy alternatives," and United Church of Canada said, "No more nuclear power stations should be built. Darlington should be abandoned, unless a public debate decides otherwise."

Operation Clean (Niagara) said

- We remain unconvinced by Ontario Hydro's arguments in support of nuclear power. The case against it may be argued on the basis of cost analysis; risks to public health and the environment from low and high level radioactive pollution; technology scale; risks of catastrophic meltdown; reliability; flexibility to meet a fluctuating demand; high capital costs requiring heavy debt and interest costs that are beyond the Province's ability to afford in a period of high interest rates; capital-employment ratio; security; resources conservation; sustainability; social acceptability,

particularly with regard to links to the nuclear arms race and the "plutonian [sic] economy" rejected by a majority of Canadians; and to the availability of alternative strategies with fewer negative aspects.

Nuclear power stations were rated more favourably than fossil-fired options and purchases but less favourably than hydro-electric dams and alternative technologies by Regional participants. Those who supported nuclear energy as an option thought misinformation was the main reason behind those opposing it. Participants in the Timmins, Winchester and Kingston meetings were generally more supportive than those in the other meetings. Examples of reasons given for support follow:

- Ontario Hydro should continue to increase nuclear power generation expansion in Ontario and Canada [because]...we could reduce acid rain by closing down coal-fired plants,...we would produce cheaper electricity and would use Canadian uranium...we would ensure the availability of electrical energy.

Some Municipal Utility participants felt that Hydro would be reluctant to commit more nuclear stations because the public is not supportive. Public perception of nuclear stations is that "they are okay but don't build any more" suggesting that the public has not accepted nuclear power. One participant suggested that after Darlington is completed the Province will have to support Ontario Hydro for additional nuclear capacity or the economy will suffer a loss of jobs. Nuclear waste was seen as an emotional issue and a suggestion was made that Hydro should change its perceived image with respect to nuclear waste management policies and procedures. Some felt that nuclear waste was not garbage, but still has value through reprocessing.

Regional participants expressing concerns about nuclear energy cited environmental impact, capital costs, the Chernobyl disaster, and potential nuclear weapons issues. Comments were made about the problems of nuclear waste disposal -- from uranium mining, irradiated fuel and plant decommissioning. Some public safety concerns arose at meetings in Atikokan, Port Hope and Barrie:

> "...a nuclear technology failure could affect hundreds and thousands of people." "...Hydro's failure to add in the hidden costs of nuclear indicated a lack of integrity." "Ontario Hydro should be generating electricity in a socially responsible way."

10.9 CO-GENERATION

There is widespread support (more than three in four responses) for Ontario Hydro becoming involved in co-generation projects as evidenced by the Market Survey results. It is considered a desirable way of making greater, more efficient use of existing energy sources. Residential consumers feel that this source will provide jobs and would create a source of competition for Hydro. There is considerable support among

commercial/industrial consumers (61%) for Hydro providing grants to companies to encourage co-generation whereby the receiving company would sell Hydro their excess electricity. However, interest in participating is relatively low. Only 14% of the commercial/industrial consumers say they would be very or somewhat interested in participating in such a program.

Provincial organizations generally approved of co-generation. However, there were comments regarding Hydro's buy back rates. Examples include:

- Provided there is a cost advantage to both producer and Ontario Hydro's customers, co-generation makes excellent sense and should be developed to the maximum degree economically justifiable. (Canadian Nuclear Association)

- Ontario Hydro needs to explore the options which small-scale generation and co-generation offer for improving the overall energy efficiency, flexibility and reliability of Ontario's energy/electrical system. (Foodland Hydro Committee)

- We advocate the promotion of co-generation and customer produced electricity and strongly recommend that in order to encourage this phase Hydro should be reimbursing for the excess power -- at least at the same rate that energy is sold to municipal electric utilities. (Ontario Cattlemen's Association)

- Ontario Hydro's buy back program must be based on realistic rates, on "full avoided cost" rather than average generating costs...the most promising alternatives to the year 2000 appear to be industrial and non-industrial co-generation and the development of the Onakawana lignite reserves. (Ontario Federation of Labour)

- In principle, the Sierra Club of Ontario supports the idea of co-generation with some reservations...There appears to be ideal circumstances where the level of co-generation could be improved, such as in the burning of by-products of the pulp and paper industry, thus providing power for its own needs. ...The Sierra Club assumes that co-generation and alternative energy sources will only be responsible for providing a small percentage of Ontario's needs, but we fully support the research needed...(Sierra Club)

- Because co-generation, and parallel generation both are small scale, the construction times will be short, and the system gains the flexibility to respond quickly when it encourages these options. (United Church)

- We consider that small customer owned generation using any available energy source should be encouraged, but not at the expense of the majority of customers in the Province. Thus, avoidable costs should be the basis for establishing the rates to be paid for net generating costs plus transmission losses if the power can be used

in the vicinity of the plant. (Municipal Electric Association)

- The rise in energy prices together with advances in technology have considerably improved the economics of co-generation. The new price policy for co-generation power is a positive move and should be accompanied by an active program of technical assistance. (Ontario Chamber of Commerce)

A municipal utility representative felt that Ontario Hydro was the vehicle that should be used to assist studies to determine if co-generation is viable. Another suggested that if there are financial incentives, co-generation could meet future energy needs. A suggestion was made that Hydro's financial incentive could be structured like a mortgage where Hydro would get the return through the rates and not be a part of the business.

One participant suggested that Hydro should not buy back the electricity for more than Hydro's production costs and present selling rates since the customer should not have to subsidize private entrepreneurs.

10.11 PURCHASES

There was a variety of views on the purchase of electricity from outside Ontario expressed by provincial organizations. Examples of these views are:

- If we can purchase a constant source of power from James Bay through Quebec Hydro cheaper than we can build expensive nuclear generating stations, we recommend this avenue. (Ontario Cattlemen's Association)

- We believe that the purchase option should have a high priority in planning considerations because of its many obvious advantages, particularly the reduction in additional generation required together with its capital funds and associated debt. (Federation of Ontario Cottagers' Association)

Some industry associations had reservations about the possibility or desirability of electricity purchases.

- ...it is understood that any large purchases from either province will require significant line construction and the building of new generation plants. (Municipal Electric Association)

- ...additional nuclear units in Ontario would most likely deliver power even more cheaply than a new large hydro-electric plant in Quebec built in the same period. Even if the price was equal, the difference between this option and indigenous options is that all the construction jobs and most of the manufacturing would be outside of the province, causing a resultant drain on the Ontario economy. (Canadian Nuclear Association)

Most of the participants in the regional meetings felt that purchases meant jobs would be lost to Quebec and Manitoba. For example, a Winchester participant stated, "...electricity imports do not provide jobs in Ontario. If we go elsewhere for electricity we'll all pay." Atikokan participants were concerned about the loss of forest land resulting from the required new transmission lines. Chatham residents were concerned about the loss of agricultural land and compensation policies related to the construction of these lines. Port Hope residents stated that relying on other Provinces means you would have greater risks of your costs going up.

However, not all participants agreed. Several Chatham participants felt that joint developments by Hydro Quebec and Ontario Hydro are acceptable and several participants in the Chatham, Timmins, Hamilton and other meetings felt that interprovincial transmission interconnections should be encouraged. This view was based on the belief that there should be federal based electricity planning to minimize risks and maximize efficiency for all Canadians.

A municipal utility representative expressed a strong desire to see jobs remain in the Province; purchases from other provinces meant the least number of jobs in Ontario. Another participant indicated that Hydro only buys intermittent power from Quebec now because Quebec can sell power to the U.S. at higher rates.

Market Survey results indicated that consumers appear reluctant to see Ontario become too dependent on buying power. Ontario's residential customers expressed concerns about the security of supply. However, there is support among the commercial/industrial consumers for buying power from Manitoba or Quebec. Six in 10 respondents feel that this option is one that should be definitely or probably considered. This option was preferred since it is perceived to require no capital outlay to build facilities. However, overall sentiment appears to favour building new generating capacity in Ontario versus buying if the costs are the same. If there is a clear cost advantage to buying, residential consumers favour following the cheapest option.

10.12 COAL

Results from the Market Survey indicate that coal is one of the least favoured options. Coal stands out as the energy source which causes the most pollution -- acid gas emissions/acid rain -- or environmental damage. Six in 10 respondents say they are concerned that new coal-fired generating stations would increase the amount of acid rain.

Most regional comments suggested low support for the coal option. Acid rain was a major concern expressed at the Hamilton, North Bay, Barrie and Winchester meetings.

Not all participants, however, were critical of coal. Participants in Atikokan, stated there was nothing wrong with coal plants installed with

scrubbers using western coal from Saskatchewan. One resident stated, "...some benefits would go out of the Province but we would gain by manufacturing their products." Because of the nuclear waste, some Atikokan participants would rather have another coal-fired plant in Northern Ontario.

Provincial Organization representatives expressed mixed comments about coal-fired stations. However, an underlying concern was with the emissions that cause acid rain. Examples are:

- The thermal source is oil from out of the province and coal from the United States or Alberta, and they contribute to the acid rain problem. Hydro's failure to install technology, that is available, to reduce harmful emissions has not helped. (Ontario Federation of Labour)

- Both the new coal option and re-commissioning the Hearn and Keith stations would contribute to the acid rain and health problems and require the installation of scrubbers. This could prove uneconomical for the mothballed plants, particularly considering how close they are to the end of their useful lives. (Canadian Nuclear Association)

- Toronto Nuclear Awareness is skeptical about Ontario Hydro's reasons for curtailing coal-fired capacity. Coal plants are a reasonably acceptable short-term supply option that can be used in the immediate future if needed. Coal should be seen as a transition fuel before conservation, rate-reform and expanded hydraulic generation are fully implemented.

10.13 OIL

Market Survey results indicate that oil along with coal is the least favoured option. Oil is seen as too expensive, causing too much air pollution, and as being in limited supply.

Regional participants expressed little support for oil-fired generation. Oil was ruled out as there appeared to be a strong belief that there would be another oil shortage.

10.14 STORAGE

Regional meetings devoted little time to the option of energy storage. It was seen, however, as one of the more acceptable options for increasing supply. In the Kingston meeting, it was acknowledged that batteries were seen to be efficient. At the same meeting, suggestions were made that Hydro should research night storage for day use. This option does not appear to be well known or understood by the public.

10.15 KEY FINDINGS

Hydraulic

- Hydraulic generation is a preferred supply option of most participants.

- Reasons for support for the hydraulic option are based on the perception of:

  - abundant supply
  - lowest cost
  - least destruction to the environment
  - indigenous supply
  - contribution to job creation
  - revenue via water rentals
  - long facility life span

- Problems cited with the hydraulic option are based on the perception of:

  - limited supply
  - water fluctuations causing safety and environmental problems
  - environment damage through flooding
  - destruction of wild rivers

- Recommendations made by participants include:

  - pursue large hydraulic where economic
  - pursue small scale hydraulic developments
  - work with municipalities, Conservation Authorities and private individuals to develop hydraulic sites
  - improve the current buy-back rate

Natural Gas

- Natural gas-fired generation is a favoured option.

- Reasons for support of the natural gas option are based on the perception of

  - being the cleanest
  - being the cheapest
  - being in abundant supply
  - having few environmental problems
  - having low handling costs

- Reasons for opposition to the natural gas option include perceptions that:

  - it is expensive
  - it is dangerous

- Recommendations made by participants include:

  - use natural gas for heating and transportation and electricity for equipment that only uses electricity

- electricity and natural gas requirements should be planned together

Alternative Energy Technologies

- Solar power is a preferred number of option and ranks high when conventional and number of options are considered. Solar is favoured as it is considered to be low cost, clean and a renewable energy source.

- Photovoltaics, and wind generation alternate technologies are viewed positively by the public.

- Wood burning generation received support in northern Ontario.

- Municipal solid waste generation received widespread support. Concerns were expressed about the toxic effluents of such plants.

- Reasons for support of alternative technologies are based on the perception that they:

  - are less capital intensive
  - are less damaging to the environment
  - use renewable resources

- Alternative energy technologies are expected to make a limited contribution, but they will be used where economic i.e. northern and remote communities

Co-generation

- There is widespread support for co-generation projects

- Reasons for support of the co-generation option are based on the perception of:

  - more efficient use of existing resources
  - job creation
  - a source of competition for Hydro

- Recommendations from participants included:

  - Hydro should work with communities, generators, etc.
  - Hydro should improve the buy-back rate for surplus electricity
  - Avoided cost should be the basis for establishing a new buy-back rate

Nuclear

- Nuclear power stations are preferred over coal plants and purchases but rank behind hydraulic, alternative technologies and natural gas

- Support for nuclear is based on the perception that it:

- is the cheapest
- is the safest
- is cost effective
- is proven
- is dependable
- creates jobs
- is indigenous
- reduces acid rain
- has radioactive wastes which can be handled

. Opposition to nuclear is based on the perception of problems related to:

- risk to public health and safety
- waste from uranium mining
- disposal of radioactive wastes
- risk to the environment
- high capital cost
- increased debt
- a relationship to nuclear weapons

Purchases

. Overall sentiment appears to favour building new generating capacity in Ontario over buying if the costs are the same.

  If there is a clear cost advantage to buying, support for purchases increases.

. Opposition to the purchase option are based on the perception that:

- there would be increased dependency for electricity on other provinces
- transmission tie lines would be required
- construction and manufacturing jobs would go outside of the Province.

Coal

. Coal fired generation is one of the least favoured options.

. Acceptance of this option increases if state-of-the-art technologies are used.

. Opposition to the coal option are based on:

- increased acid rain
- use of high cost fuel from outside province

Oil

- Oil fired generation is one of the least-favoured options
- Reasons for opposition to the oil option include:
  - it is too expensive
  - it causes acid rain
  - it is in limited supply
  - the perception that there will be shortages again

Storage

- The pumped storage option is not well known, nor understood.

11.0 Government Consultation and the Select Committee on Energy

Government consultation activities included briefings of Provincial and Federal Government Ministries, government sponsored conferences, reviews of government publications and testimony before the Select Committee. These activities provided opportunities for Hydro to discuss and consider ideas and emerging policy directions on planning for future electricity requirements with the government.

Hydro participated in two conferences on energy sponsored by the Province -- Energy 2000 and Small Hydro. The Energy 2000 conference, held in late 1985, was a major international energy symposium which focussed on the importance of energy issues, supply options and trends and policies in Ontario's future. Two detailed papers by the Ministry of Energy -- The Shape of Ontario's Energy Demand and Fuelling Ontario's Future were reviewed by Hydro. In March, 1986 the Small Hydro Conference examined the progress by Ontario's small hydro industry during the last five years.

Hydro staff have also reviewed a series of Provincial and Federal Government publications on electricity as part of the research and analysis activities of the demand/supply study. These publications include: Parallel Generation in Ontario, New Directions for Meeting Tomorrow's Electricity Needs, Streams of Power and the Memorandum of Understanding between the Federal and Provincial Governments on Conservation.

The deliberations of the Select Committee on Energy culminated in 26 recommendations to the Provincial legislature on Ontario Hydro affairs. During the Committee hearings Hydro requested direction from the Committee on five specific topics (see Figure 2). The answers to these questions are addressed and cross-referenced by the Select Committee with the 26 recommendations in its final report.

Demand Options

1. Should Ontario Hydro influence demand? If so, how? Conservation?

Promotion? Or both?

Demand side options - load shifting, strategic load growth and conservation have an important role to play in a balanced electricity system. The Committee has directed Hydro to develop a comprehensive conservation stategy (Recommendation 9) and to take steps to develop a stronger capability for acquiring conservation resources (Recommendation 10). The Ministry of Energy (Recommendation 19) and the Ontario Energy board (Recommenation 18) are recommended by the Committee as the bodies that should review and evaluate Hydro's strategic marketing and resource plans to ensure a balanced system. The Ministry of Energy was instructed (Recommendation 11) to investigate the feasibility and desirability of developing labelling programs and efficiency standards for appliances and/or changes to the building code.

2. What criteria should be used to evaluate conservation programs?

The Committee has recommended that Hydro develop a mix of resource options based on criteria of cost, flexibility and reliability. The use of planning and forecasting methodologies based on adequate end use data is recommended to ensure that demand options are treated equally in the planning process (Recommenations 5 and 6).

3. Should conservation potential be limited by the "no losers" screening test?

Ontario Hydro has been directed by the Committee not to use the "no losers" test. In its place, Hydro should develop comprehensive strategies directed at distributing the benefits of conservation to all customer groups (Recommendation 9).

Supply Options

4. Should priority be given to certain supply options?

The Committee recommends that Hydro pursue cost-effective options that are flexible and help diversify our resource mix e.g. accessible, cost effective hydraulic sites and parallel generation (co-generation, small hydro and municipal solid waste) in accordance with Ministry of Energy parameters (Recommendations 13 and 14). The major firm purchase agreement option should not be pursued at present, however, the pursuit of improved interconnections with Quebec will keep the option open for review in the mid 1990s (Recommenation 15).

5. How can approval times be redued?

To improve the approval process, the Committee recommends that Hydro expand its planning process to include industry allies and informed public groups (Recommendatins 17 to 20).

The provincial government has acted upon two of the Committee's recommendations that Darlington NGS should proceed and that an independent review of the safety of the design, operating procedures and emergency plans associated with Hydro's CANDU nuclear plants should be undertaken.

The balance of the committee's recommendations are currently being considered by the provincial government.

12.0 Strategy

Public opinions expressed during Consultation Program activities suggest that there are a number of important strategic factors Hydro should consider when planning for the Province's future electricity needs.

Customer priorities as discussed in previous sections which Ontario Hydro should address are:

- maintain reliability of supply
- maintain reasonable rates
- minimize environmental damage
- encourage consumers to use electricity wisely and efficiently
- provide an electrical system that is flexible
- provide an electrical system which uses a diversity of fuel sources
- contribute to the Province's economy.
- constrain Hydro's borrowing and increases in debt
- minimize social and land use impacts
- maximize public safety
- pursue options that result in equity and fairness
- minimize lifestyle adjustment.
- pursue options that favour reliance on indigenous energy sources.
- a range of choices for electricity consumers with the emphasis on voluntary versus mandatory participation in demand management.
- demand management options first before commitments are made to supply options to meet longer term needs.
- smaller, more flexible supply options and hydraulic before large nuclear or fossil plant options.
- hydro should have a lead role in the option selection process.
- consultation should continue with the public as the study progresses to ensure that their needs and expectations are met.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT F

ANALYSIS OF REPRESENTATIVE PLANS

October 1987

System Planning Division

3449G

Foreword

This report gives more detail than will be found in Chapter 10 of the main report "Meeting Future Energy Needs - Draft Demand/Supply Planning Strategy". Should further detail still be required, the reader is referred to the reference reports listed at the end of this report.

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CONTENTS

FIGURES

1.0 INTRODUCTION

To determine the general direction or strategy for demand/supply planning it is necessary to go beyond the look at the individual options as presented in Chapter 8 or in the Reference documents 651SP and 652SP. There are various reasons for this. The comparison of individual options in Chapter 8 focussed on lifecycle costs and technical feasibility. As described in Chapter 7 there are many more criteria to be considered, such as impact on rates, lead times, timing and flexibility and manpower requirements. Factors such as these cannot be treated on a 'per MW' basis. The absolute level of activities is important, and timing and flexibility cannot be assessed without looking at total programs.

Another major reason is that directions or strategies for demand/supply planning often contain a mix of resources or technologies, and these can only be examined by looking at representative plans with the appropriate mix of resources. In some cases technologies may be competing to perform the same role, there may be limited scope for others, while others may complement each other. These are some of the reasons it is necessary to look at and compare total programs or plans.

The objective of the Analysis of Alternative Representative Plans is to draw lessons from the plans with respect to the major planning issues facing Ontario Hydro.

Fifteen basic plans have been assessed. The plans have been designed to illustrate:

- extreme strategies with respect to either demand or supply side options;
- the impact of not pursuing the nuclear option,
- the impact of delaying starting work on supply side programs and
- the impact of adopting centralized vs dispersed siting of generation resources.

The plans were developed in 1985 for the 1988-2010 time period, assuming no decisions were made until 1988. Some longer term issues were also identified. These issues include the replacement of firm purchases, and replacement of aging plant. The post 2010 financial impacts are allowed for.

For each of the fifteen plans a flexibility analysis has been carried out to assess the ability and cost of modifying the plans to accommodate other future situations outside the most likely forecast.

2.0 BUILDING BLOCKS

The plans used options identified in Chapter 8 and selected in order of their "standard" costs. The standard cost is the levelized cost of meeting a new increment in demand. For further discussion of Standard Costs the reader is referred to the appendix of the supplementary report on The Options.

2.1 Demand Options

The amounts of the demand side measures assumed are shown in Figure 2.1.

The amount of load shifting that is useful is determined by the daily load shape. The daily variation of demand is not very large. Demand is at a minimum through the night. It rises sharply in the morning, fluctuates slightly through the daytime until it starts declining to its nighttime minimum in the late evening. The fluctuations through the day are met by the peaking hydraulic plant, leaving a 16 hour plateau to be met by thermal plant, and a relatively smaller nighttime valley. The size of the nighttime valley is such that only about 1000 MW of peak load shifting can be accomodated before the load curve met by the thermal plant is completely flat.

With regard to efficiency improvements, options with standard costs less or equal to coal fired generation were used. Two levels of incentives, moderate and high, and hence two alternate levels of contribution to load reduction are assumed. The two different levels are designed to cover the range of possibilities. Under the high case, incentives would be provided up to the full cost of the efficiency improvement measures. These costs applied over a reduced total system demand would raise the customers' average rates more than for the alternative supply option, though total customer service costs should be lower. The moderate case is thought to be about the level of incentive that could be offered without rates increasing any more than they would have for implementation of the lowest cost supply option.

Work to date on demand management has given little guidance on how much new load growth could be affected by efficiency improvement measures. It has been assumed that, at most, the new load growth could be reduced by 20%, i.e. if load were forecast to increase by 1000 MW, this could be reduced to 800 MW.

In building up the aggregate programs all demand programs were started in 1990. This gives four years (1986-1990) for design and demonstration programs. It is recognized that if timing permitted, priority would probably be given to new market opportunities, then load shifting and finally, retrofit efficiency measures, as this is the cheapest order in which to do them. However, the requirement to demonstrate delivery capability and the possibility of higher than expected load growth dictated starting all programs in 1990. The times shown in Figure 2.1 to phase-in the full contributions, ranging from 7 to 15 years, reflect U.S. experience.

Ontario Hydro recognizes that its information on demand management is poor. The estimates of potential shown in Figure 2.1 are very uncertain. This is recognized in the analysis, various levels of success being considered.

Figure 2.1

DEMAND SIDE OPTIONS AND ASSUMED POTENTIALS

LOAD SHIFTING

	LOAD GROWTH	POTENTIAL
	Most Likely	75 MW/YR
	Upper	125 MW/YR

EFFICIENCY IMPROVEMENTS

	RETROFIT MARKET	NEW MARKET REDUCTION IN LOAD GROWTH
Incentive		
- 50%	550 MW	10%
- 100%	2200 MW	20%

NOTES:

1. Load shifting potential is limited by the system characteristics.
2. Efficiency improvements are expected to be phased in over 10-15 years, the shortest is 7 years.
3. All options start in 1990.
4. Quantities independent of marginal supply option (coal).
5. Level of incentive does not change in any plan.

2.2 Supply Options

The supply side options used are shown in Figure 2.2. Further details can be found in Supplementary Document "The Options" and Reference Document 651 and 652SP. The fact that Ontario Hydro owns few undeveloped sites was recognized.

The purchases from Quebec and/or Manitoba to displace new coal-fired generation were costed at 80% of a new coal-fired plant. Purchases to displace or delay new nuclear plant were costed at 90% and 130% of nuclear. There are ongoing studies and negotiations with both Manitoba and Quebec to determine purchase quantities, timing and pricing. These negotiations are focusing on relating the purchase price to nuclear plant costs.

2.3 Transmission

The transmission reinforcements approved for eastern Ontario are assumed. The transmission reinforcements assumed for southwestern Ontario (Plan 7) are now superceded by an alternative plan (Plan 1) that has been approved by the Consolidated Hearings Board. This change in the southwestern Ontario transmission plan does not change the results of analysis of representive demand/supply options plans. Other reinforcements assumed in northern and southern Ontario are identified in Figure 2.3. This base transmission system is essential for all the plans, and is effectively independent of uncertainties in load growth and demand option penetrations.

Additional bulk transmission was required for the alternative plans to connect new generating stations in Ontario and purchases from Manitoba and Quebec into the system, to strengthen inter-regional transmission for system security, and to supply the increasing load levels. The major inter-regional facilities required over the study period for the most likely load forecast would be a new high capacity East-West interconnection and a North-South reinforcement.

Figure 2.2

SUPPLY SIDE OPTIONS AND ASSUMED POTENTIAL

OPTION		POTENTIAL
NUCLEAR	4 x 880 MW design	Potential limited by lead time
FOSSIL	4 x 500 MW subcritical U.S. coal fuelled or	Potential limited by lead time
	200 - 500 MW integrated coal gasification combined cycle (IGCC), Single or multiple (up to 4) unit stations	Potential limited by lead time
COMBUSTION TURBINES	25MW to 200MW units fuelled by oil or gas	Potential limited by lead time
HYDRAULIC	Little Jackfish	132 MW
	Niagara	540 MW
	Mattagami	406 MW
	Others	up to 1700 MW
PURCHASES	up to 4500 MW	500 MW from Manitoba up to 4000 MW from Quebec
LIFE EXTENSIONS REHABILITATIONS	Lennox, Lakeview, Hearn, Keith	
SUPPLEMENTAL OR NON-UTILITY GENERATION	Cogeneration, Municipal solid waste generation, Small hydraulic	300 - 1000 MW Maximum unit size of 200 MW

Figure 2.3

BULK POWER TRANSMISSION REINFORCEMENTS
ASSUMED I/S BY 2000

Southwestern Ontario Plan 7

- 1x1 CCT Bruce x Essa 500 kV line
- 1x2 CCT Bruce x London 500 kV line
- 1x1 CCT Nanticoke x London 500 kV line
- 1x1 CCT London x Sarnia and/or Windsor area 500 kV line

Eastern Ontario Plan 3

- 2x1 CCT Lennox x Hawthorne 500 kV line
- 1x1 CCT Hawthorne x St. Lawrence 500 kV line

Southern Ontario

- 1x2 CCT Milton x Middleport 500 kV line
- 2nd 1x2 CCT Lennox x Bowmanville x Cherrywood 500 kV line
- 2nd 1x2 CCT Cherrywood x Claireville 500 kV line
- 2nd 1x2 CCT Milton x Trafalgar 500 kV line

Northern Ontario

- 2x1 CCT Hamner x Mississagi lines operated at 500 kV

Notes:

1. Southwestern Ontario Plan 1 was approved by the Consolidated Hearings Board, in place of Plan 7. However, the results of this study are not changed by this.

2. 1x2 CCT means one double lined circuit.

3.0 ALTERNATIVE PLANNING STRATEGIES

The alternative plans fall into four main families:

- All Supply - various mixes of supply development with no additional demand management;

- Demand - primary reliance on demand options with different supply alternatives when demand is insufficient;

- Distributed Resources - to reduce the need for new transmission; similar to demand programs with small fossil plants if required;

- Mixed Plans - moderate level of demand management with different combinations of supply options; also demonstrates variations to timing of nuclear approvals and construction.

Within each family variants were developed to reflect either different incentive levels or the use of different supply technologies. Within the mixed plans variants were developed with different amounts of planning activity in the 1988-92 time periods, and hence different amounts of flexibility. The full list is shown in Figure 3.1. and descriptions of the plans and their resource requirements can be found in Appendix A.

For each variant an illustrative plan was developed including the amount and inservice date for each type of resource. Figures 3.2 gives an indication of the demand and supply resources required by 2010 for each plan. The resource requirements for these plans are based on (1) the most likely load forecast scenario, (2) assuming the necessary approvals are obtained and (3) the medium level of demand side contribution materializes. The diagrams in Appendix A give a graphical representation of this information.

Figure 3.3 shows the requirements in the upper load growth scenario, again assuming the necessary approvals are obtained and the medium demand side contribution.

No further resources are required under the low load growth scenario before 2010.

Figure 3.1

ALTERNATIVE DEVELOPMENT STRATEGIES

BROAD STRATEGY FAMILY	PLANS	DESIGNATION
ALL SUPPLY		
	NUCLEAR	AS
	PURCHASE & FOSSIL	H
	FOSSIL	C
DEMAND		
	PRICE	P
	INCENTIVE (HIGH) & PRICE	AD
	INCENTIVE (HIGH) & NUCLEAR	J
DISTRIBUTED RESOURCES		
	INCENTIVES (HIGH) & FOSSIL	G
	INCENTIVES (MODERATE) & FOSSIL	L
MIXED (ALL HAVE MODERATE INCENTIVE DEMAND MANAGEMENT)		
	NUCLEAR - WITH FLEXIBILITY	B
	NUCLEAR - DELAYED	F
	NUCLEAR - LIMITED FLEXIBILITY	I
	NUCLEAR - SMOOTHED	D
	PURCHASE & FOSSIL	E
	FOSSIL	K
	NUCLEAR - DELAYED BY PURCHASE	Q

FIGURE 3.2

DEMAND/SUPPLY NEW RESOURCES BY THE YEAR 2010 (MW)

	DEMAND		SUPPLY			PURCHASE	
PLAN+	MANAGEMENT	NUCLEAR	HYDRO	FOSSIL	REHABS	COGEN	HQM
AS	0	7929	1563	-	LKV*	550	-
H	0	-	1849	2875	LKV	550	4500
C	0	-	1849	7475	LKV	550	-
AD	6513*	-	669	-	LKV	1200	-
J	5600	3524	669	-	-	1200	
G	5600	-	1356	460	LKV	1200	-
L	2950	-	1849	4140	LKV	550	-
B	2950	7048	1067	-	-	550	-
F	2950	6167	1984	-	-	550	-
I	2950	7048	1067	-	-	550	-
D	2950	7048	669	-	-	550	-
E	3580	-	1563	1725	LKV	550	2500
K	3580	-	1849	4025	LKV	550	-
Q	3580	4405	1067	-	-	550	2500

+ SEE FIGURE 3.1 FOR EXPLANATION OF CODE LETTERS
* INCLUDES 913 MW OF PRICE DRIVEN CONSERVATION
** LAKEVIEW - 2296 MW

ASSUMPTIONS: MOST LIKELY FORECAST
APPROVALS OBTAINED
EXPECTED DEMAND SIDE CONTRIBUTION

FIGURE 3.3

DEMAND/SUPPLY NEW RESOURCES BY THE YEAR 2010 (MW)
UPPER LOAD GROWTH

	DEMAND	SUPPLY			PURCHASE
PLAN	MANAGEMENT	NUCLEAR (#881 MW)	HYDRO	FOSSIL (#510 MW)	HQ & MH
AS	0	16	2100	-	-
H	0	-	1860	32	4500
C	0	-	1860	40	-
AD	20530*	-	669	-	-
J	8100	14	2042	3	
G	8100	-	1860	42**	-
L	4650	-	1860	54**	-
B	4650	15	2384	8	-
F	4650	10	2541	16	-
I	4650	15	2042	9	-
D	4650	20	2384	0	-
E	4650	-	1860	28	2500
K	4650	-	1860	32	-
Q	4650	15	2042	5	2500

Assumptions: Upper Load Growth
Approvals obtained
Expected demand side contribution
Lakeview, Hearn & Keith Rehabilitation
Supplemental Generation Program Extended to 1200 MW
* Includes 12430 MW of price driven conservation
** Includes 500 MW & 200 MW units in the ratio 2.1

4.0 EVALUATION METHODOLOGY

The representative plans discussed in Section 3 were assessed using the following evaluation factors:

- physical resource requirements, i.e. the amounts and timing of new transmission & generation

- fuel supply and acid gas control

- long run economics; i.e. present value of costs

- customer cost; as reflected in the average cost of electricity and total service cost

- financial impacts; such as borrowing requirements

- social, community and natural environmental impacts; and

- provincial economy impact, i.e. jobs and level of economic activity.

In these assessments both the most likely and upper load forecasts were considered. It was also assumed that there would be no delays for approvals and the medium level of market penetration was achieved.

In addition, the adaptability of the plans to changing conditions (risk/flexibility) was also assessed in terms of resource requirements and long run economics. These evaluations addressed the following:

(a) possible acceptance or rejection of approvals for major new supply options;

(b) different market penetration rates or capacity/energy reductions from demand management options;

(c) effects of delaying or advancing decisions on supply options; and

(d) misestimation of future capital or fuel costs.

The evaluations were done by functional specialists throughout Ontario Hydro. System Planning Division staff produced the resource requirements for each plan. Using a computer model they calculated the fuel burns, cash flows, rates and borrowings. The cash flows were used to calculate the long run economics. The resource requirements, fuel burns and cash flows were used by specialists to determine the social, environmental and provincial economy impacts. The resource data and the individual assessments can be found in the reference reports listed in Section 10. The following sections highlight the conclusions of those reports.

5.0 DEMAND/SUPPLY RESOURCE REQUIREMENTS, FLEXIBILITY AND LONG-TERM ISSUES

In developing the representative resource plans, a number of messages became clear, these are detailed below.

1) Contribution of Demand Management

Demand Management can make an efective contribution to meeting electricity needs, but cannot be relied upon to meet all needs economically.

Using the high incentive demand management program and supplement generation, the most likely load growth can be met until 2008 without using major new generation facilities post Darlington, if existing plant can be renovated and the demand management contribution is as expected.

Figure 5.1 shows the total required generation in the future, after allowing for high demand management programs with the penetration expected if a high level of incentives is used. Allowance is also made for a continuing program of hydraulic developments and for a high level of supplementary generation. The figure shows that the requirements exceed the amount of existing and committed generation in 2007.

The upper load growth cannot be met by identified demand side measures alone.

Figure 5.2 shows the date major new resources are needed in the Upper Scenario. To maintain reliability beyond the need date, further, more expensive, efficiency improvements would have to be identified and funded; or further price induced conservation would have to be used, or further supply facilities would be required.

To use price increases to control demand would require real electricity rates to be higher by some 20-200% by 2010, depending on the load forecast.

A possible tool of demand/supply balancing is curtailment pricing, in which the price is set specifically to limit the quantity demanded to be no more than supply capability.

The most likely load growth can be met by demand management measures such as load shifting and efficiency improvement, together with supplemental generation and a smooth hydraulic program until about 2007. Using price to choke off demand for the rest of the decade would require average rates to increase some 20% in real terms. In the upper load growth scenario, where more curtailment would be required, the prices would have to triple.

In order to be able to make the maximum contribution to meeting the upper load growth requirements, and an orderly contribution to the most likely load growth, demand management programs need to be started by 1990 or earlier.

Given the uncertainty in the contribution of demand management, and the desire to implement the programs efficiently, market demonstration programs need to be given high priority.

If a low load growth scenario develops the demand management programs could be retuned relatively easily and painlessly.

FIGURE 5.1

DEMAND/SUPPLY BALANCE - ALL DEMAND PLAN

MOST LIKELY LOAD GROWTH

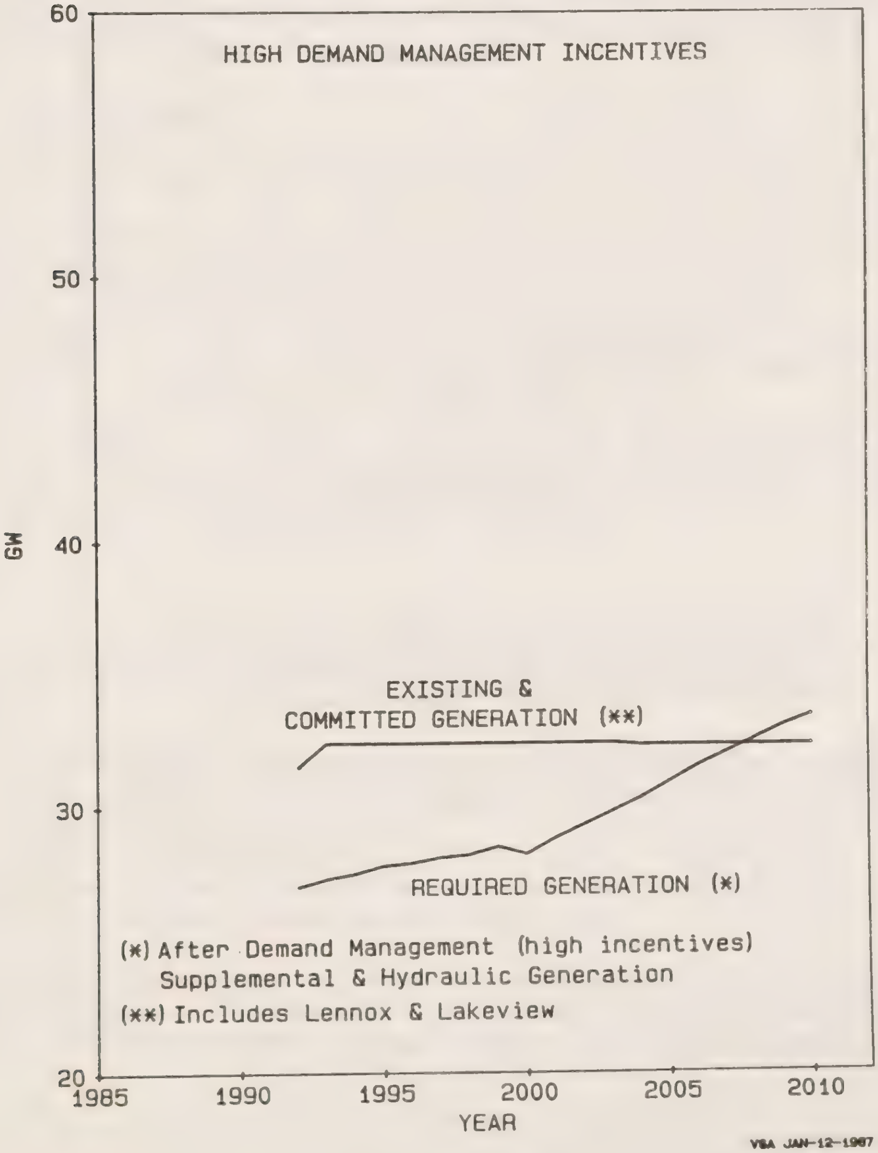
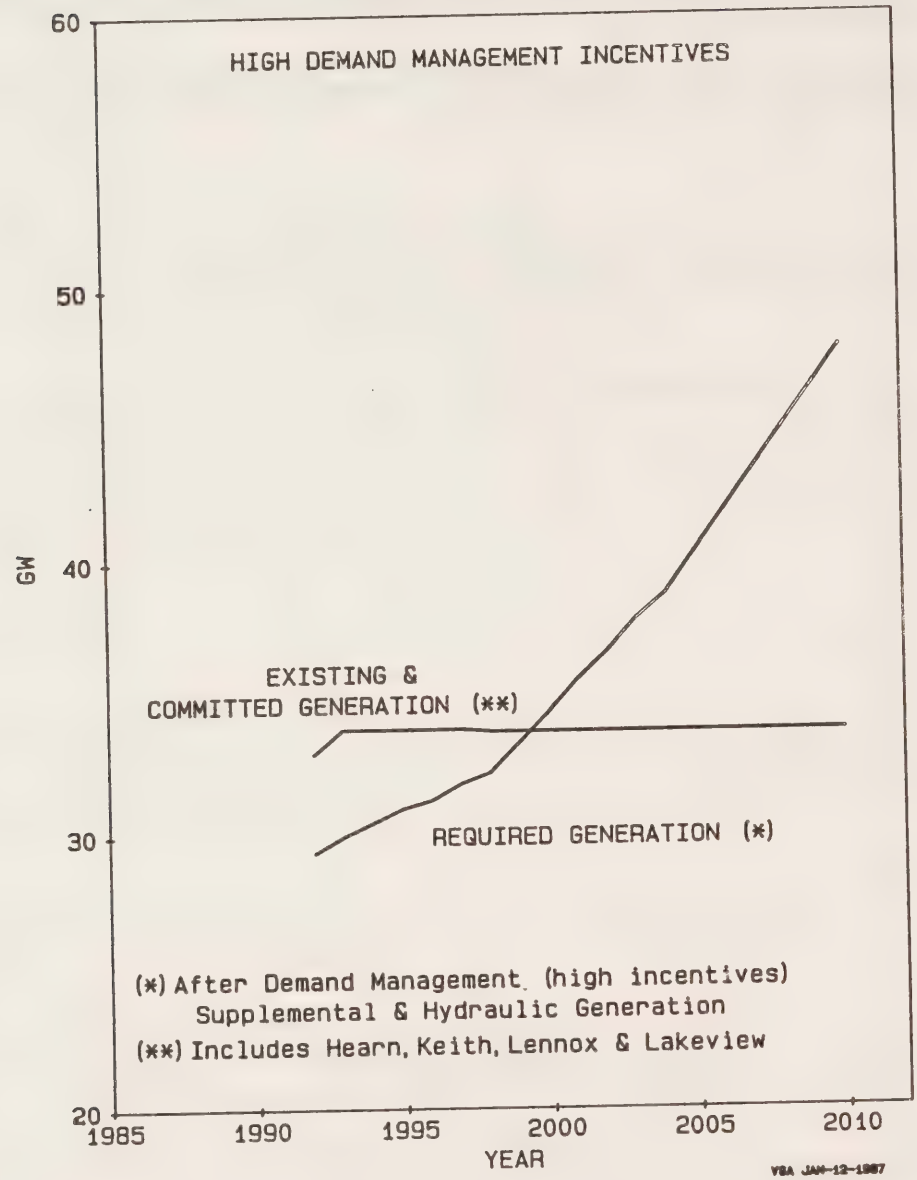


FIGURE 5.2
DEMAND/SUPPLY BALANCE - ALL DEMAND PLAN
UPPER LOAD GROWTH



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2) Unit Size

> The load growth in the 1990s and 2000s is such that large central generation stations can be used effectively. Indeed the load growth is forecast to be such that to meet it with small generation units around the province would require many smaller sites.

The annual load growth in the 2000-2010 time period, to be met by supply-side and demand-side measures, is expected to be some 750 MW/year. By that time, unless new lower cost technologies are developed, the bulk of the retrofit efficiency improvement will have been done. The scope for Ontario Hydro to effect the long term load growth is not clear, but load management programs might reduce the load growth by 10-20%. Given the economies of scale and that construction costs are minimized by bringing units into service at about 1 year intervals, 500 MW - 1000 MW units could still be appropriate. Although multi-unit stations are desirable, it may be prudent to commit the units to construction individually rather than committing all the units simultaneously.

3) Nuclear and Fossil

Nuclear is the lowest cost supply alternative for major energy production.

> There is still sufficient lead time that the most likely load growth (to 2010) can be met with nuclear plant and without using any new fossil plant, but it will require using existing fossil plants and may require rehabilitating some plant to extend their useful lives.

Figure 5.3 shows the approximate times at which preconstruction activity (planning, approval processes, pre-engineering) for new nuclear stations would have to be started, assuming that they have lead times of around 13-16 years, and moderate demand management programs.

However:

> It is very unlikely that the upper load growth can be met without using shorter lead time and more expensive (fossil) plant.
>
> There is a need to start the EA for new station(s) on existing site(s) as soon as possible if reliability is to be maintained in the upper load growth and the use of further fossil stations minimized. The requirement for further bulk transmission facilities and new sites for nuclear stations could be such that planning for these should start immediately.

Figure 5.4 shows the times at which preconstruction activity should be started if the upper load growth is to be met reliably assuming a high incentive demand management program. The figure also assumes a continuing

FIGURE 5.3
TIMING OF PRECONSTRUCTION ACTIVITY
MOST LIKELY LOAD GROWTH

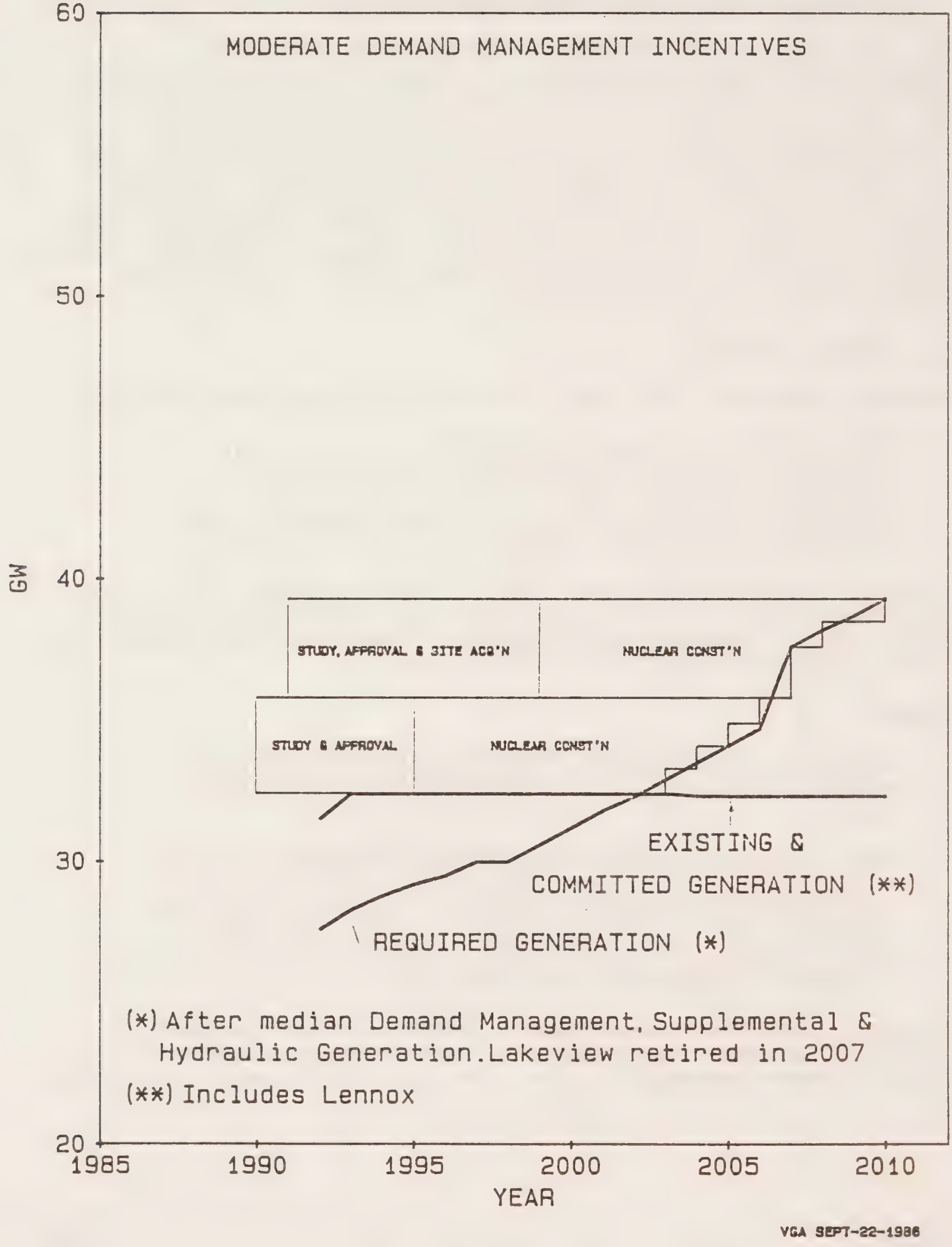

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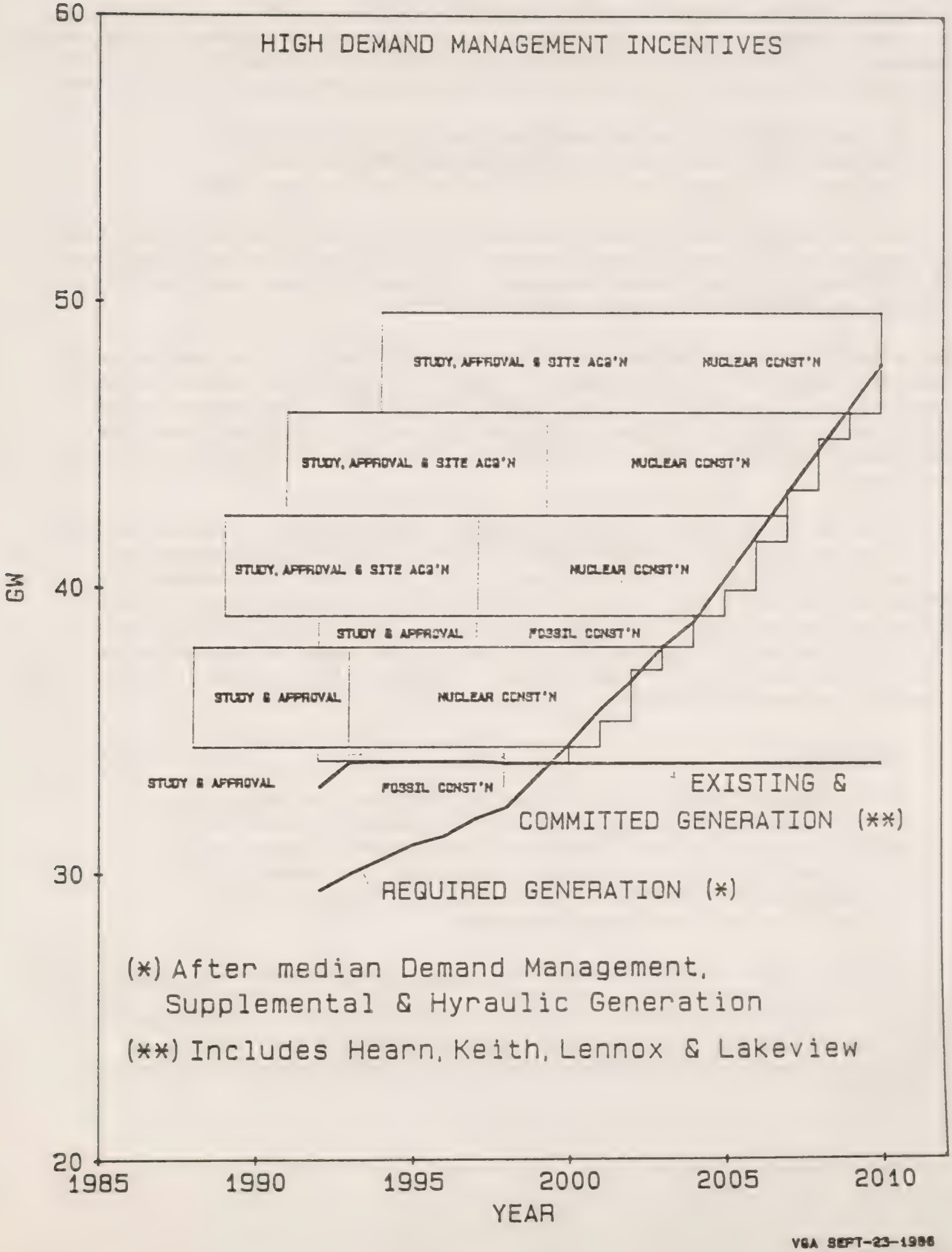
FIGURE 5.4
TIMING OF PRECONSTRUCTION ACTIVITY
UPPER LOAD GROWTH



program of hydraulic and supplemental generation. Another assumption is that the first nuclear and the first fossil station would go on sites already owned by Ontario Hydro. They therefore have shorter lead times. It shows that planning for a nuclear plant, if desired, should start as soon as possible. It also shows fossil plant is needed because it would not be possible to meet the upper load growth with nuclear plant alone because of the lead times assumed, even if high incentive demand management programs are implemented. Figure 5.5 shows the preconstruction actions required to meet the upper load growth if a moderate demand management program is followed.

If the strategy is to be based on fossil plant, or it is believed lead times can be substantially reduced, then preconstruction work need not be started until around 1989.

All the strategies can be made flexible enough to adapt to the wide range of forecasts, to failure to obtain approval for nuclear plant, and to a range of contributions from demand management. However, higher cost coal or gas fuelled options may have to be used.

Representative plans can be formulated for each family of strategies which maintain the reliability of supply. Figure 5.6 shows the amount of plant required in the upper load growth scenarios by 2000. New nuclear plant could not be approved and built by this date with the assumed lead times. The range reflects different assumptions as to the contribution of demand management.

It should be noted that the plans, because they were only formulated up to 2010, ignore some potential problems. We will need to be prepared to replace or rehabilitate the large amount of plant that will be reaching the end of its useful life shortly after the end of the study period. CO_2 emissions may need to be reduced to minimize long-term climatic changes. Plans that maintain the capability to use a wide range of technologies, including nuclear, are to be preferred from this long term point of view, as they are the most adaptable.

4) Transmission

Development of the bulk transmission system at the existing 500 kV voltage level was found to be suitable for integrating each of the full range of plans and load growth scenarios considered over the study period out to 2010. However, there are significant differences in the timing and amounts of transmission required among the plans.

Transmission aspects were investigated at a conceptual level to assess major impacts of the plans on the development of the 500 kV transmission system in Ontario. In particular, the effects of the geographic distribution of the demand/supply options on the timing, extent and security of the bulk transmission system and the associated generic environmental impacts were considered.

FIGURE 5.5
TIMING OF PRECONSTRUCTION ACTIVITY
UPPER LOAD GROWTH

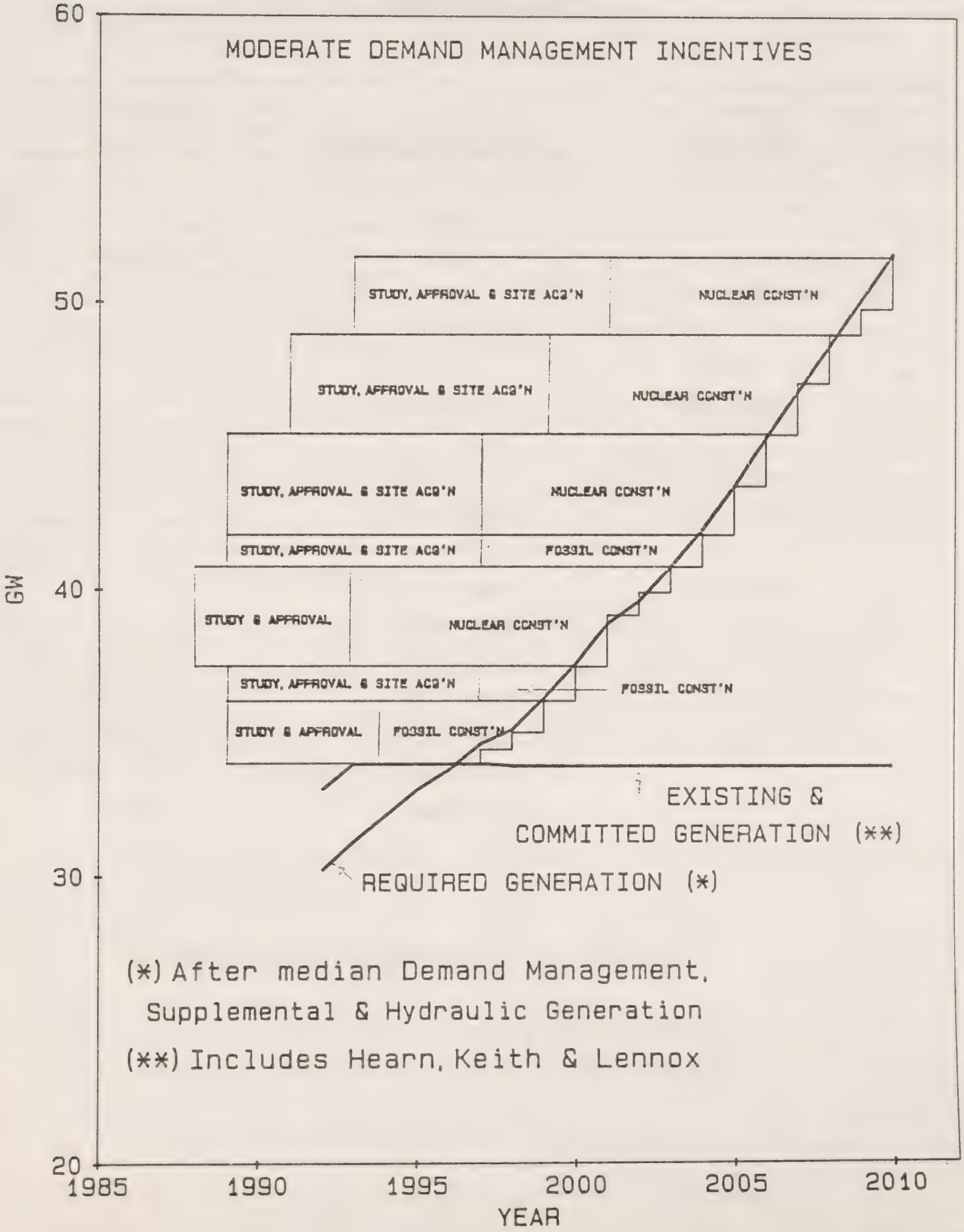


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FIGURE 5.6

DEMAND/SUPPLY REQUIREMENTS BY THE YEAR 2000 (MW)

UPPER LOAD GROWTH

PLAN	DEMAND MANAGEMENT	SUPPLY REQUIREMENT	PURCHASE HQ x MH
AS	0	8300	-
H	0	6800	1500
C	0	8300	-
AD	6790*	670	-
J	2550-6250	555-5140	
G	2550-6250	550-5140	-
L	1050-3750	3660-7000	-
B	1050-3750	3660-7000	-
F	"	3660-7000	-
I	"	3660-7000	-
D	"	3660-7000	-
E	"	2160-5500	1500
K	"	3660-7000	-
Q	"	1160-4500	2500

* INCLUDES 1010 MW OF PRICE DRIVEN CONSERVATION

REHABS: HEARN & KEITH

COGEN : 1000 MW

A strong base system is needed for all the plans studied. The transmission reinforcements required for the base system have either been committed or their approval is being sought. The additional transmission components required are different for each plan. For example, demand management reduces requirements, and together with suitable siting of fossil generation in northern Ontario can defer the need for a high capacity East-West interconnection and a third North-South line, to beyond the study period.

There are trade-offs to be made between transmission requirements and generation siting. Where possible a siting sequence was used that preserved the balance between generation and load across the province. This delayed the need for new inter-regional transmission while maintaining adequate system security. Thus for nuclear plans the first generating station after Darlington would be on a site already owned by Ontario Hydro on Lake Ontario. This would be followed by stations on northern Lake Huron and in southwestern Ontario. Locating a further nuclear station on Lake Ontario would require a new transmission corridor across Toronto to ensure adequate system security in the low probability event of a loss of right-of-way contingency. The transmission environmental considerations for this and other components are discussed in Section 6.5.1.

Should the load growth be higher than forecast, the generation facilities required in the most likely load growth case, for the all supply and mixed plans, would likely suffice to about 2001. The in-service dates of specific transmission components would be substantially different owing to the higher load levels and lead time constraints imposed on generation siting. Further transmission would be required in all areas of the province. At the present time it is difficult to foresee how these facilities could be put in place within the lead times available.

Whereas the distributed resource plans avoid the need for new inter-regional transmission their performance relative to the mixed plans remains to be investigated. Particular aspects that need to be considered are: the generation reserve margin required on a regional basis to maintain the same reliability of supply as the mixed plans, and the operating cost penalty from being unable to utilize the lowest cost generation to supply most of the energy because of transmission limitations.

6.0 IMPACT ASSESSMENTS

6.1 Long Run Economics

A major objective is to minimize long run costs. Ontario Hydro and customer expenditures have been identified and costed for all plans. Allowance has been made for the different economic conditions in the different load growth scenarios, and the impacts of the changes in electricity rates on the demand for electricity. The cash flows post 2010 have been allowed for by the use of a terminal value. The costs have been present valued using Ontario Hydro's discount rate. These lifetime costs for each plan are shown in Figure 6.1 for the most likely and upper load growths. Also shown are expenditures over the next 5 years. The economics of the price driven strategy are not shown due to the difficulty in estimating the social cost of much higher electricity rates that arise under this strategy.

The key messages are:

> The use of demand management does not adversely affect long run costs, but promoting large programs in advance of need could be expensive.

Comparison of plans with different levels of demand management (none, moderate incentives, and high incentives) suggest that the demand management is being modelled as being installed too quickly in the cases with high incentives and the most likely load growth.

> The most significant strategy choice in terms of long run costs is the use of nuclear plants. If the strategy does not use new nuclear plants, or if approval is sought but not obtained, and coal fired plants are used instead as the major energy producer, then there is a cost penalty of some $5-6 Billion (pv) for the most probable load growth. In the upper load growth case the cost is up to $10 Billion (pv).
>
> The most expensive strategies are those that depend heavily on fossil generation.
>
> The economics of purchases depends, naturally enough, on the cost of the purchase.

To the accuracy of the modelling, the mixed plans with nuclear (B, D, F, I) and the All Supply (Nuclear) plan (AS) have substantially the same cost if everything turns out as expected. Other plans are more expensive. Purchase based strategies (H, E & Q) are $1 to 7 billion more expensive, depending on whether the purchase is followed by nuclear or fossil and on the price paid for the purchased electricity. Plan J, maximum demand followed by nuclear, is about $4 billion more expensive though this is largely due to poor timing. The remaining plans are estimated to be $6 billion (1985 pv) more expensive than the mixed plans.

FIGURE 6.1

LONG RUN COSTS

NET PRESENT VALUE OF ALTERNATIVE PLANS & PLANNING COSTS ($1985 Million)

PLAN	ALL AS EXPECTED	UPPER LOAD GROWTH	PRE 1992 PLANNING COSTS
AS	+1100	+2800	500
H	+7000	+13800	400
C	+7500	+14400	200
P	-	-	0
AD	+5400	-	200
J	+3900	-1800	600
G	+5600	+900	300
L	+5900	+1300	200
B	BASE ($87,000 million)	BASE ($110,000 million)	600
F	-200	+3200	100
I	-300	0	300
D	-300	-3000	500
E	+5000	+10000	400
K	+4700	+9900	200
Q	+600 to +1400*	-400 to +1000*	700

* Range depends on pricing assumptions for purchase.

Much of the penalty associated with the plans with fossil & purchases, the distributed resource plan and the high incentive and price demand plan arises from the heavy coal burn towards the end of the study period and post 2010. If a lower cost option (e.g. nuclear) is introduced into these plans at that time, it substantially reduces the economic disadvantage of these plans.

The upper load growth scenario illustrates the value of shortening lead times for nuclear plant. Plan D, with its hypothesized 8 year lead time is the lowest cost plan. Mixed Plans with nuclear (B) and purchases (Q) and the high incentive nuclear demand Plan (J) are slightly more costly. Delaying, by four years, decisions on nuclear plant costs about $6000 million and using fossil plant costs $6-16 billion.

Under the low growth scenario, no further resources are required. If low growth is recognized in the next five years then no major commitments would have been made, with the possible exception of a purchase from Manitoba or Quebec.

Only the plans with purchases may require commitment of construction prior to 1990. While the other plans do spend significant amounts of money on approval processes, preliminary engineering or market demonstrations prior to 1990, no long-term commitment to large scale capital spending is made, and thus, the plans without purchases can adapt to lower growth without a large financial penalty.

If it were possible to reduce the total lead time for nuclear to eight years, and to start a program straight away, such a strategy would save about $200 million (pv) under the forecast load growth and $3 billion under the upper load growth. It would however be at risk to a lower load growth scenario. Individual unit commitment would give a lower probability of premature commitment. Also, as can be observed from comparison of Plan B and D, advanced commitment of nuclear plant, because of its low operating costs, can be economic.

The results of this scenario analysis support the conclusions of a more detailed study on the effect of lead times in the face of uncertainty in future load growth. (See Reference Report "The Optimal Level of Planning Activity".) The results in that report support planning activities to maintain the ability to meet a load growth about 1 1/2% per year higher than the most likely. That is approximately the relation between the upper and most likely load growth scenarios.

The cost of planning and approval stages for a nuclear plant are much less than the expected long-term benefits.

The cost of the planning and approval stages for a nuclear station is about $200 M. Nuclear plans have an expected cost $4-7 billion (pv) less than strategies based mainly on fossil. An analysis of the possibilities shows that a strategy of delay has the same "expected" cost as starting work on approvals straight away. This analysis assumed that probability of obtaining approval for a nuclear station at the present time is poor, but

that either waiting until the need date is closer, demonstrably high load growth, or if demand management market testing showed a need, would increase the probability of obtaining approvals.

Under the forecast load growth, lower penetration rates for demand options with a mixed plan (B) would involve building and operating more expensive options but would be balanced by the savings on demand management measures. Under the upper load growth the alternative measures would cost about $1 billion more. High penetrations would allow some postponement of more expensive options and lower fuelling cost. These results indicate that the timing, costs and incentives assumed in the mixed plans for demand management are about right for the most likely load growth, but could be increased somewhat if the load were higher than expected.

There is considerable uncertainty in the future price of coal and some uncertainty as to how much nuclear stations are going to cost to construct in the future. However, under all the sensitivities studied, nuclear stations are the most economic source of major energy supply.

6.2 Fuel Supply and Acid Gas Control

> The timing and amount of fossil fuel burn, and the requirement for acid gas control measures can be significantly affected by the choice of plan.

Figure 6.2 shows the total system coal burn for a variety of representative plans, for the most likely load growth. A wide pattern of burns can be seen. There are difficulties under the scenarios where the burn goes down to very low levels and then increases rapidly. Fossil burns below about 5 million tons/year (15 TW.h) jeopardize the ability to maintain the required flexibility of supply. The high burn scenarios could pose significant problems with coal transportation, handling and storage facilities. This would be especially true if it was decided to distribute the new coal fired stations across the province. From a fuel supply point of view all strategies are all manageable, provided sufficient notice is given. Preference from a coal supply point of view would be for a stable, and predictable levels of coal burn.

> Strategies with the maximum contribution from demand management (high incentives) can substantially delay the need to retrofit acid gas control technology on existing stations. Nuclear is the only way to keep coal burns down in the long term, but purchases and demand management can reduce the size of the peak coal burn.

New coal burning stations will have acid gas control technology. Retrofitting control technology is expensive. Figure 6.3 shows the coal burn from existing stations, under the most likely load growth. In the

FIGURE 6.2
TOTAL SYSTEM COAL BURN
MOST LIKELY LOAD GROWTH

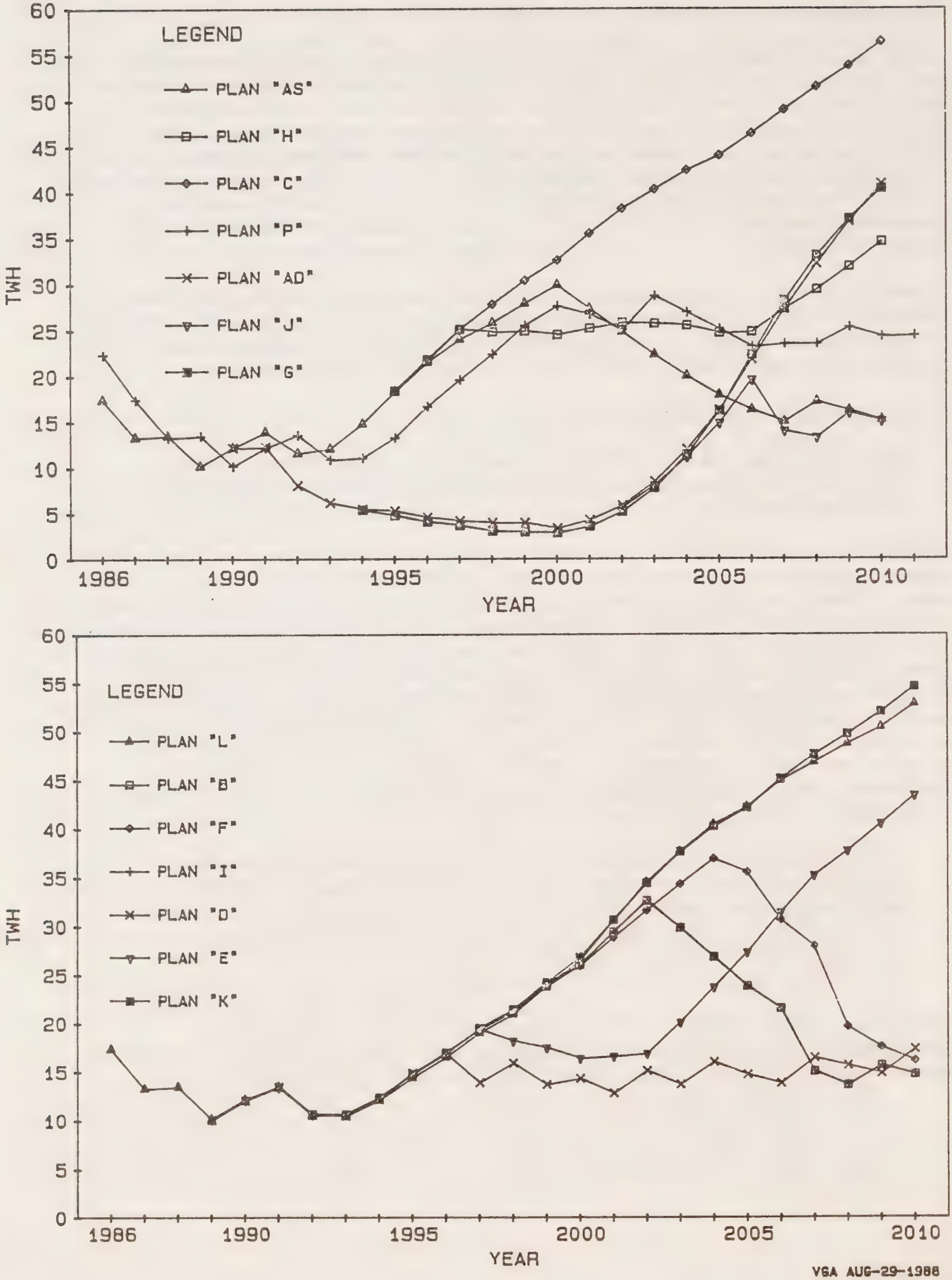
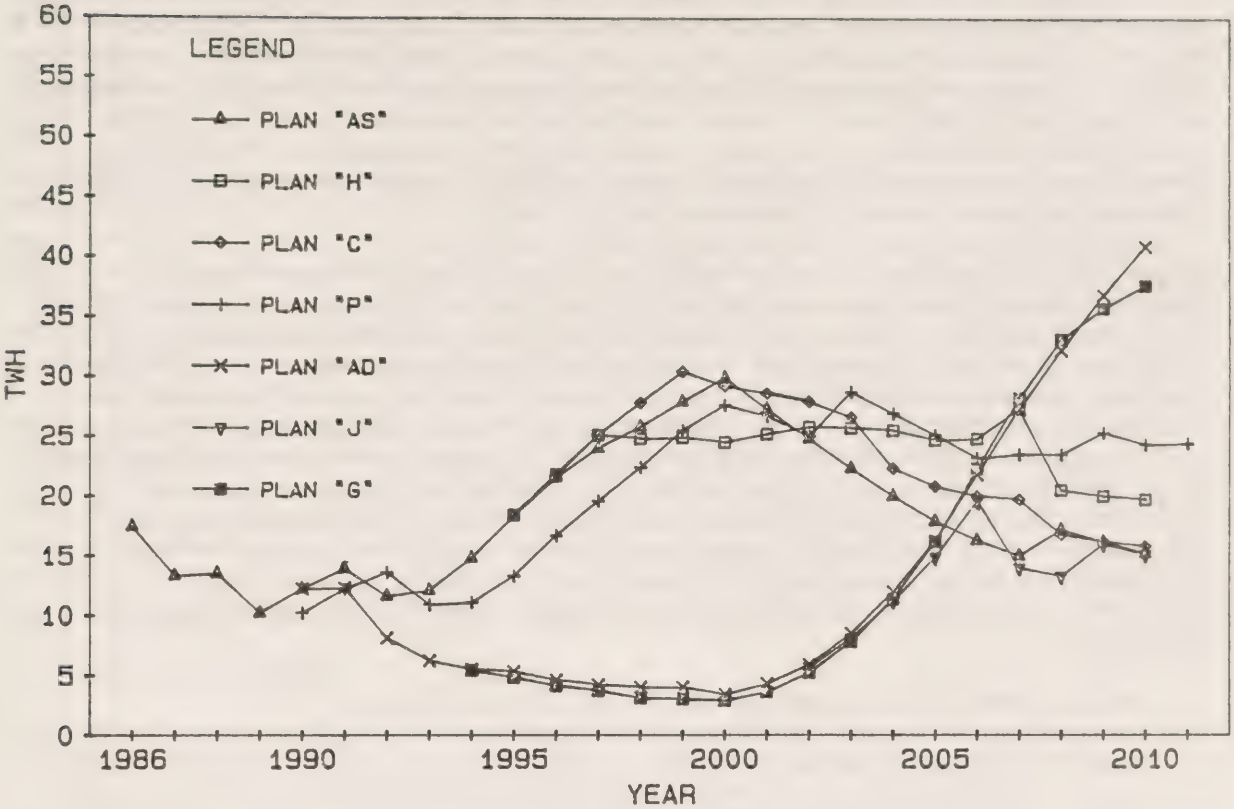
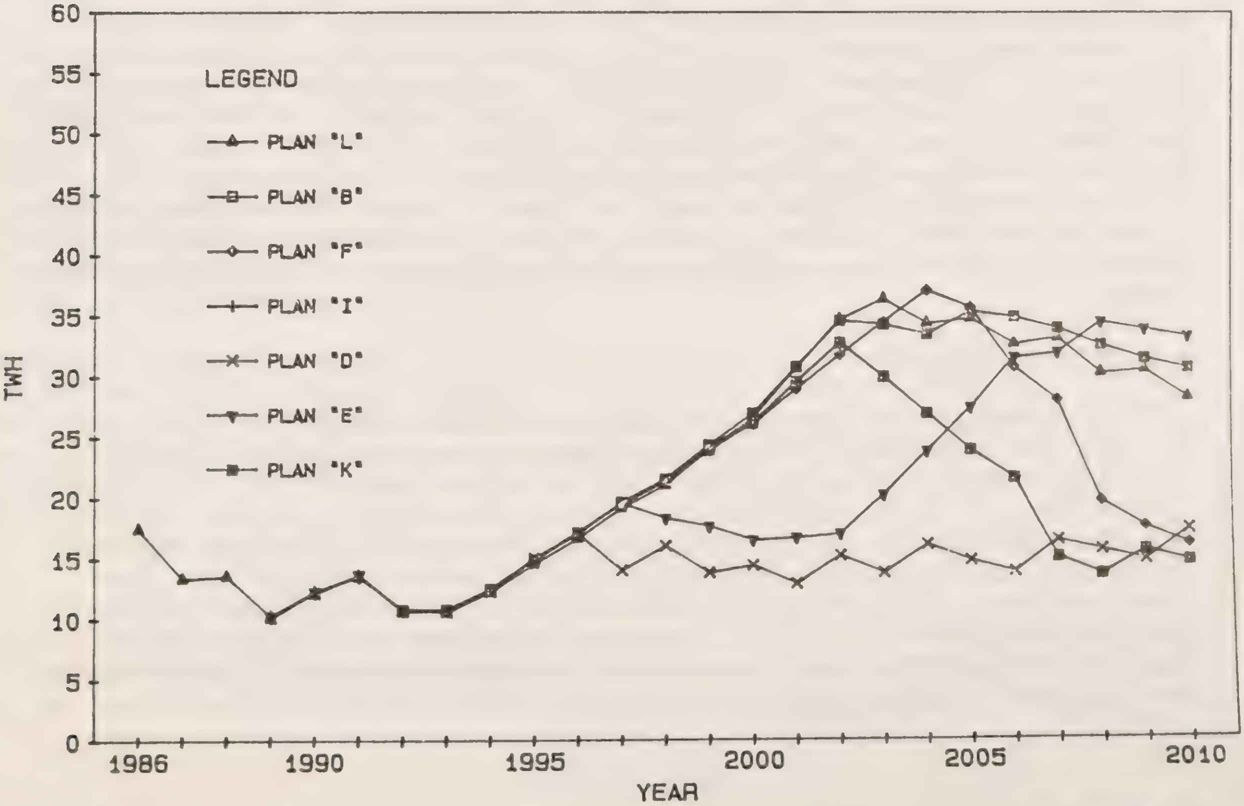


FIGURE 6.3
COAL BURN, EXISTING STATIONS
MOST LIKELY LOAD GROWTH





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short term only the demand (high incentives) plans (AD, J) and the Distributed Resources (G) plan are such that acid gas control measures could be put off until the turn of the century if the load grows as expected. However, these plans suffer in the longer term if the conservation potential is fully exploited and system load growth either has to be met by new and/or existing coal-fired plant. There could also be problems building up the coal supply contracts at the rate required. The alternative of following demand management with a nuclear plant, (Plan J) keeps the coal burn within reasonable limits even in the upper load growth.

Plans with no nuclear but with major purchases (E and H) also keep the fossil burn in check through 1995-2005 time period, though at a higher level which would require four to eight scrubbers. These plans also suffer towards the end of the period, when the purchase is no longer enough to meet the load growth, unless the purchases are followed by nuclear generation. Because of the assumption that the amount of demand management is limited, the only plans which show a long term capability to control coal burns, are those with nuclear plant. The sooner the new nuclear plant is brought in service, the better from this point of view. The longer the nuclear is delayed the more the fossil burn rises before being checked and reduced. This pattern of fuel burn would be very hard to supply cheaply and efficiently, and meeting acid gas regulations economically could also be difficult.

> Unless there are further advances in acid gas control technology, the upper load growth case with a fossil future is impractical past the year 2005.

Coal burns under the upper growth scenario would be nearly twice as high as those in the equivalent plans under forecast load growth. The peak coal burn even under a mixed plan (B) would require scrubbers or their equivalent on about 14 coal burning units and a short period of expensive measures such as burning gas and cutting exports in order to remain within the acid gas limit. If fossil stations were built instead of nuclear, even installing Integrated Gasification Combined Cycle (IGCC) units which have very low acid gas emissions, we would be unable to meet the acid gas limits unless we replaced existing stations with IGCC. The nitrogen oxide part of the acid gas regulations could be another limiting factor along with sulphur oxides.

6.3 Customer Costs

> The strategies that emphasize demand management show higher rate levels in the 1990s. Rate levels for all other plans are consistently lower until after the turn of the century.

Provided the load follows the most probable forecast, the average cost of electricity under the alternative plans follow essentially the same time trend, with declining average price through the 1990s, and approximately constant real price thereafter. The only exceptions to this pattern are the plans with large efficiency improvement programs where Ontario Hydro pays the full cost - demand plans AD & J and distributed plan G. These plans, as

shown in Figure 6.4, could have higher average electricity prices than the other plans through the 1990s and early 2000s. The magnitude of the effect will depend on the accounting policy adopted. Figure 6.4 assumes that investments in demand management are depreciated over 5 years. If a depreciation life of 10 years is used the effect is reduced, but still significant.

Rate levels are generally higher in the upper load growth scenario (Figure 6.5), with no significant declines from current levels materializing over the study period. The possible difference in rate patterns between the high incentive demand strategies and the others seen in the Most Likely scenario, is also evident in this the upper scenario. The high demand orientated strategies exhibit higher rate levels, up to 20% more expensive, in the 1990s as even more money must be invested to moderate demand growth. But rate levels tend to converge around 2000. Post 2000 the rates for plans which rely on fossil plant can be seen to be increasing in real terms, while those depending on nuclear remain at substantially the same real price.

Even though rates are higher in the 1990s for plans with high incentives paid for demand management, total customer electricity service costs over the study period are not. This is because of the lower use resulting from the efficiency improvement and is shown in Figure 6.6.

6.4 Financial Impacts

> The total level of capital expenditures in the various plans does not give grounds for differentiating between the plans. The only exceptions are those plans which use price to choke off demands.

This is because the major components: efficiency improvements, nuclear and fossil, are all capital intensive. This lack of differentiation is especially marked in the upper load growth where the conservation options are a smaller portion of the total programs and where the ability to build nuclear in time restricts the nuclear programs. Under the most likely load growth the increase in capital expenditures can be delayed by the appropriate choice of strategy. Thus plans with moderate incentives, fossil plant or purchases appear better having lower expenditures. High incentives raise the borrowing requirements in the short term.

A further concern is the rate at which expenditures on demand management would have to be increased in the upper load growth scenario when the efficiency improvement would be required as soon as possible. It takes time for an organization to build up to spending $600-1000 M/year in a new area of operations. This is also reflected in the human resource picture (Section 7). However, this is no different to that that which was required for the first nuclear plants.

The plans require different levels of expenditures in the short term to maintain the possibility to meet the load growth reliably and economically. These monies, while not large compared to the total capital expenditures,

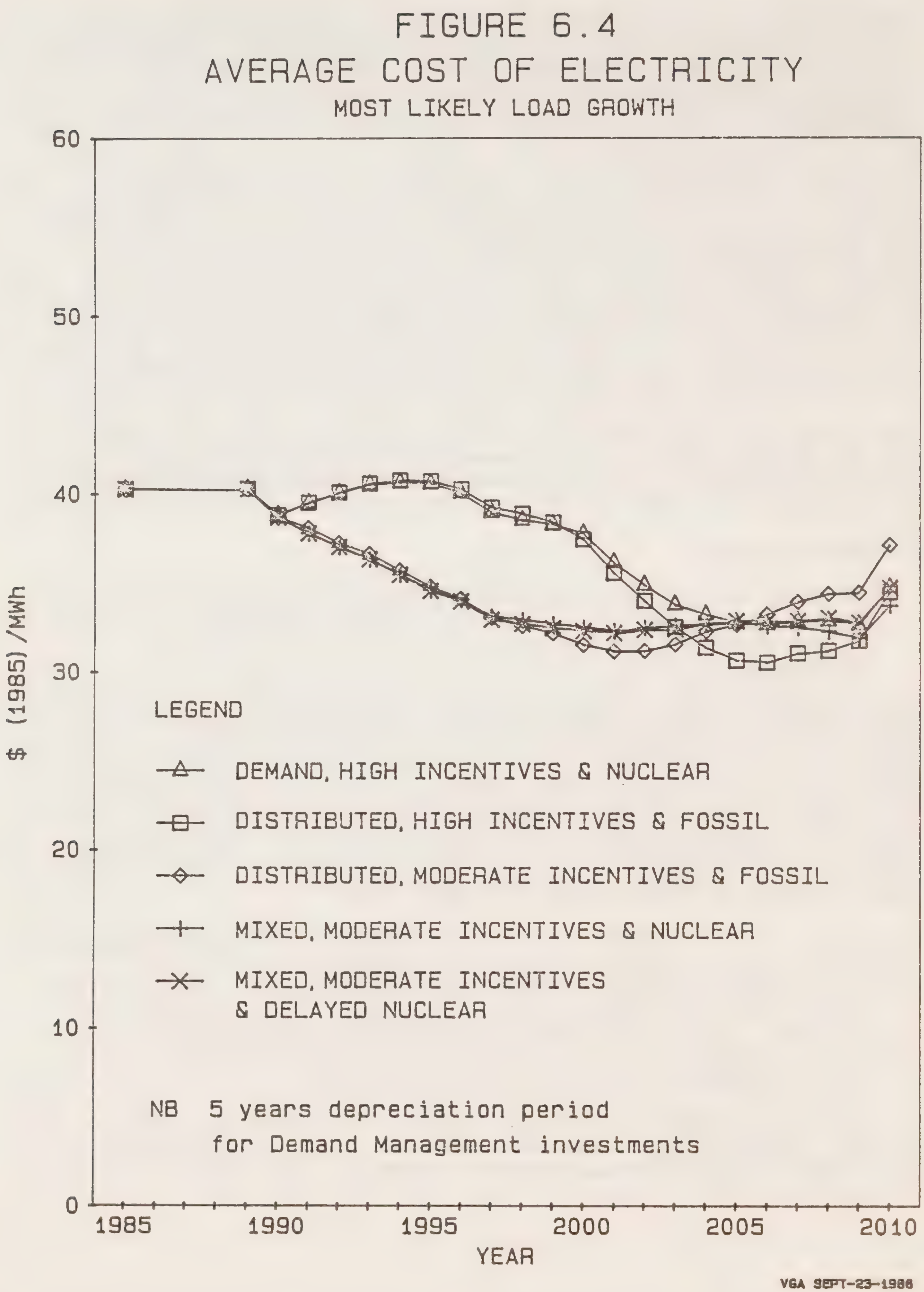
FIGURE 6.4
AVERAGE COST OF ELECTRICITY
MOST LIKELY LOAD GROWTH
60
50
40
30
20
10
0
$ (1985) /MWh
1985
1990
1995
2000
2005
2010
YEAR
LEGEND
DEMAND, HIGH INCENTIVES & NUCLEAR
DISTRIBUTED, HIGH INCENTIVES & FOSSIL
DISTRIBUTED, MODERATE INCENTIVES & FOSSIL
MIXED, MODERATE INCENTIVES & NUCLEAR
MIXED, MODERATE INCENTIVES
& DELAYED NUCLEAR
NB 5 years depreciation period
for Demand Management investments
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FIGURE 6.5
AVERAGE COST OF ELECTRICITY
UPPER LOAD GROWTH

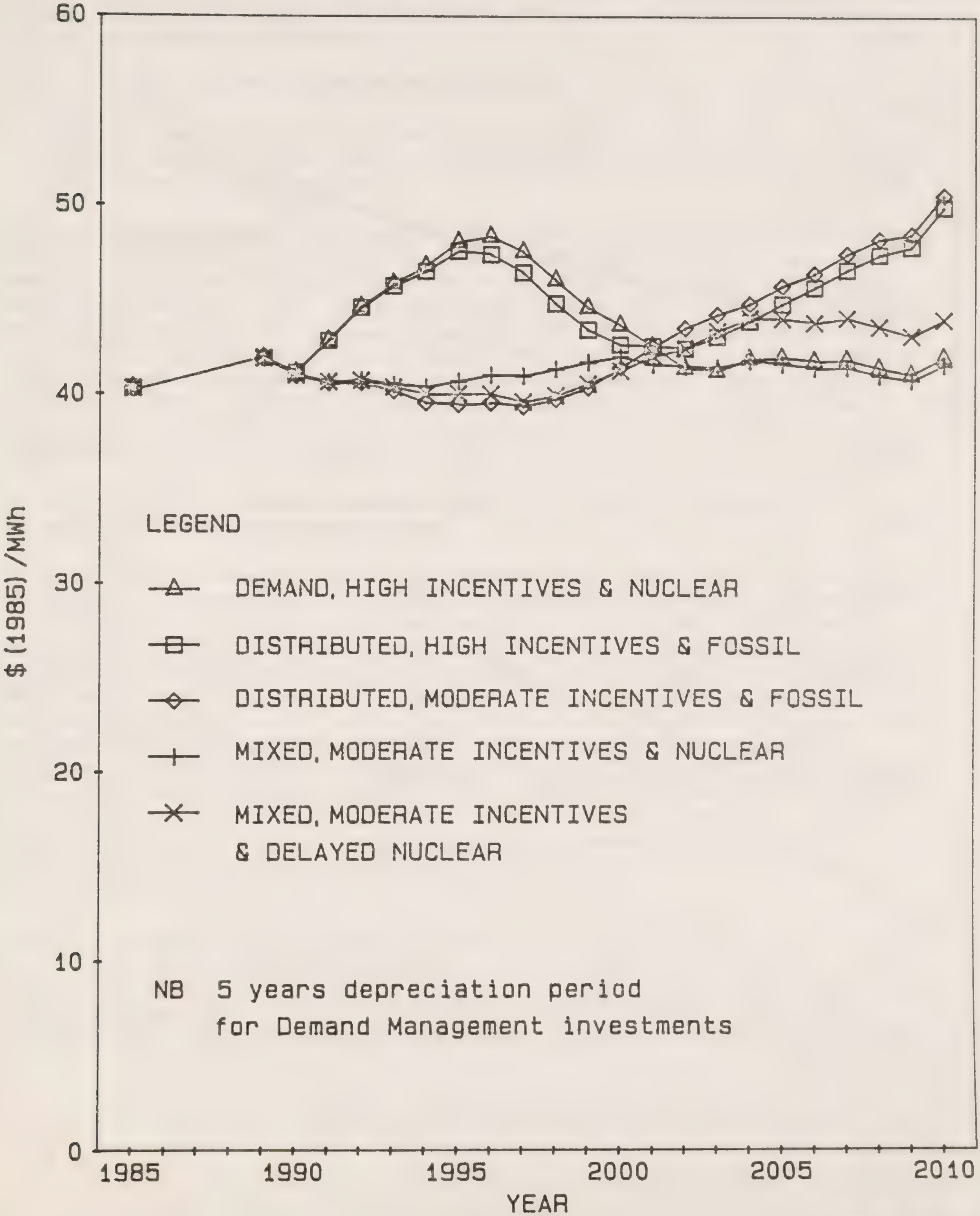

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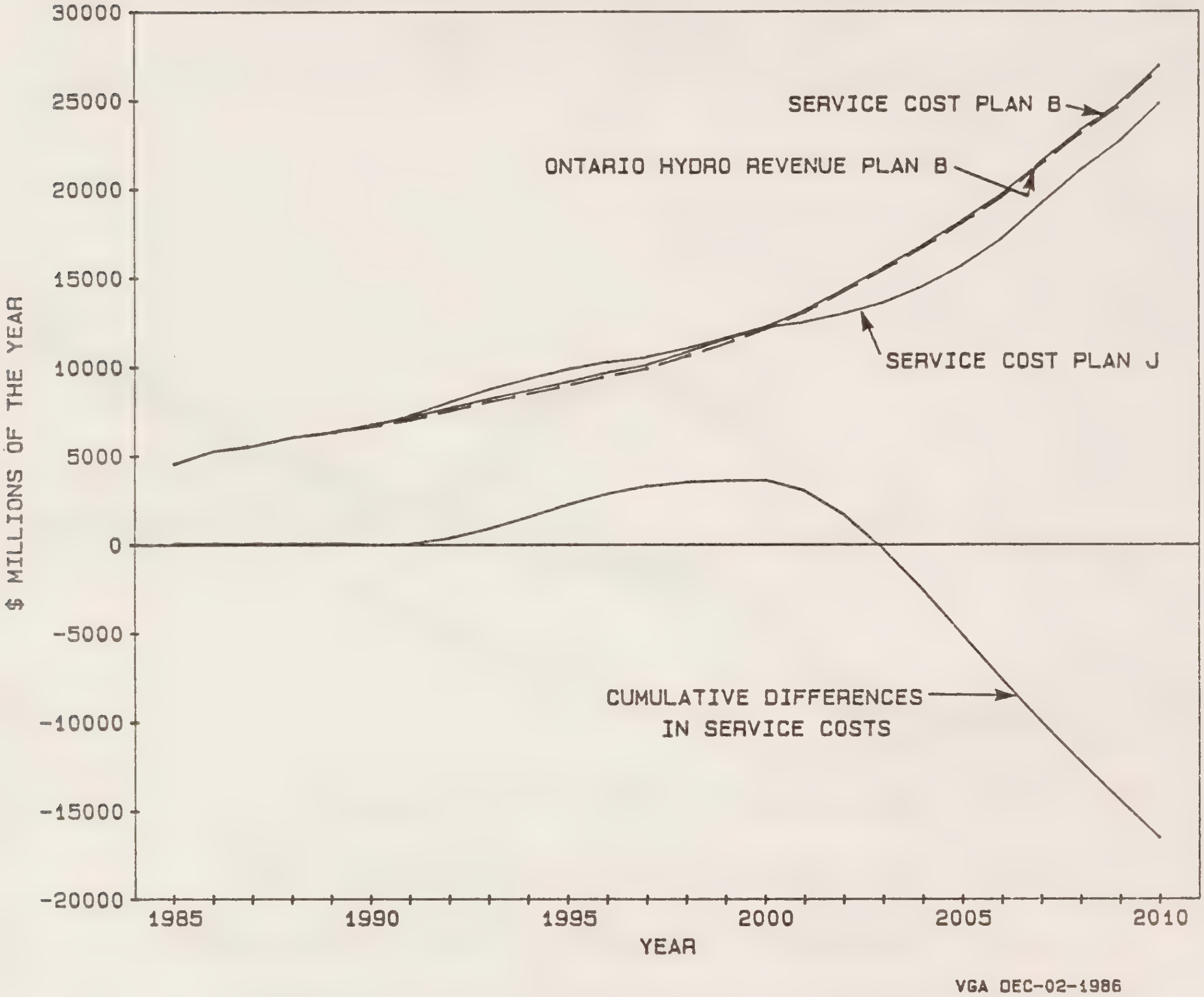
FIGURE 6.6
TOTAL SERVICE COSTS
MIXED RESOURCE (B) VS ALL DEMAND (J)



NOTE : Most Likely Load Forecast

could be significant, coming when there is heavy pressure to reduce costs. The sums involved are shown in Figure 6.1. To minimize short run costs, the best decision is no decision or adoption of plan dependent on purchases or fossil plant. If nuclear is to be used further, then decisions to that effect should, from this perspective, be postponed as long as possible. It should, however, be noted that delaying the start of planning and approval activities reduces flexibility.

> Under the most likely load growth, all plans have levels of capital borrowing that likely could be handled with little or no disruption of capital markets.

Figure 6.7 shows the gross borrowing requirements in the most likely load growth. The demand-oriented options exhibit the lowest relative borrowing levels, as they require relatively smaller capital investments compared to supply alternatives. Most of the other options exhibit patterns of rising borrowings over time, with the only significant differences being in the timing (i.e., purchase options or demand management can delay the borrowings for nuclear construction). These levels of borrowing can likely be handed with little impact on Hydro's position in capital markets. This assumes that up to 20% of requirements can be borrowed offshore (non-Canadian) and immediately swapped into Canadian dollars.

> All plans in the Upper Scenario, indicate significant amounts of offshore borrowing.

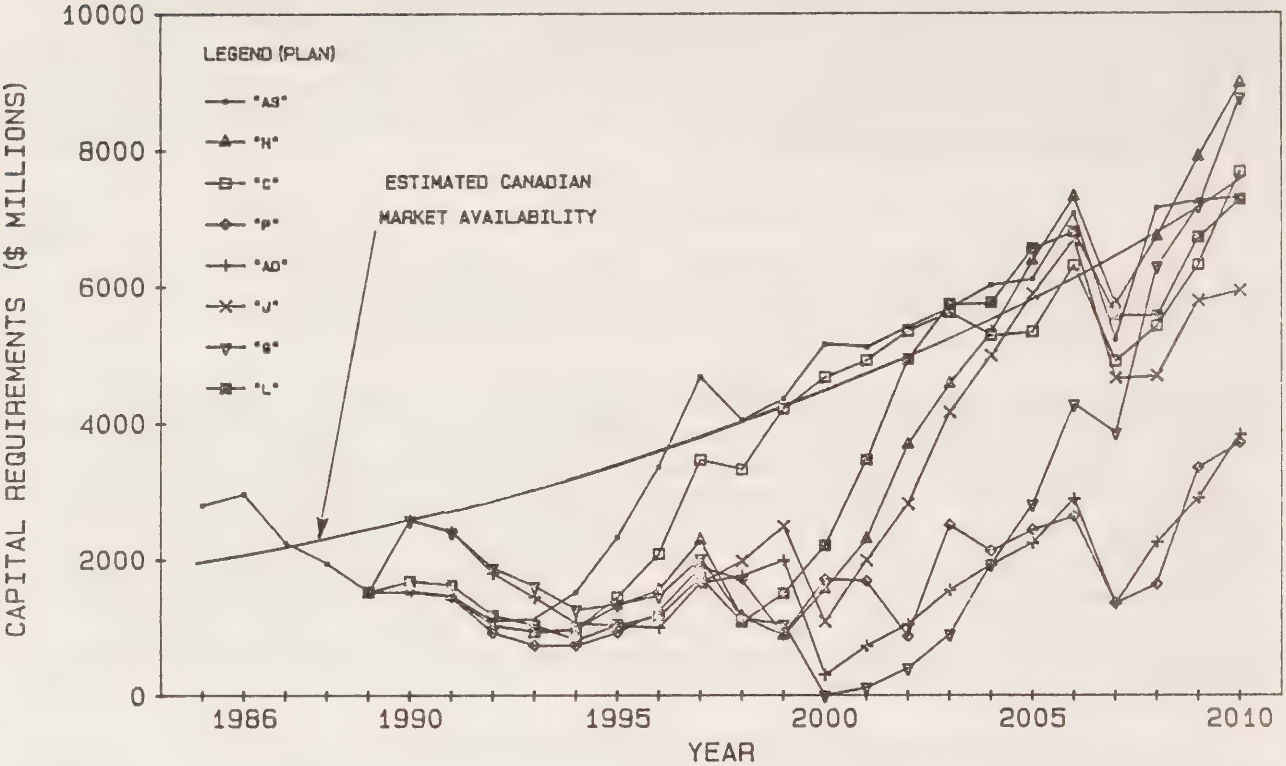
The upper growth scenario brings borrowings to the forefront as an issue (Figure 6.8). Except for the all demand scenario (AD), which would require large amounts of price-induced conservation, all plans require substantial levels of borrowings from the late 1990s and onwards, involving significant amounts of offshore (non-Canadian) financing. Up to 50% of borrowing from 1995 onwards would potentially have to be offshore. The issue here is more the desirability of such a financing program in the context of corporate and government policy than Hydro's ability to obtain such funds. Current financing policies require the swapping of all new foreign borrowings into Canadian dollars. The availability of a volume of swaps implied in the high level of foreign borrowing, is an uncertainty that increases risk. Such large amounts of foreign borrowings would also severely restrict the Corporation's flexibility to take advantage of potential cost and risk reducing restructuring of the debt portfolio.

However, there is a large degree of uncertainty in assessing the implications of such borrowing levels. In an extended upper growth scenario, a trade-off between the need for a reliable electricity supply and achieving manageable borrowing requirements may be required. Alternative capital market sources and net income alternatives would have to be explored.

FIGURE 6.7

BORROWING REQUIREMENTS ($ MILLIONS)

MOST LIKELY LOAD GROWTH PLANS



BORROWING REQUIREMENTS ($ MILLIONS)

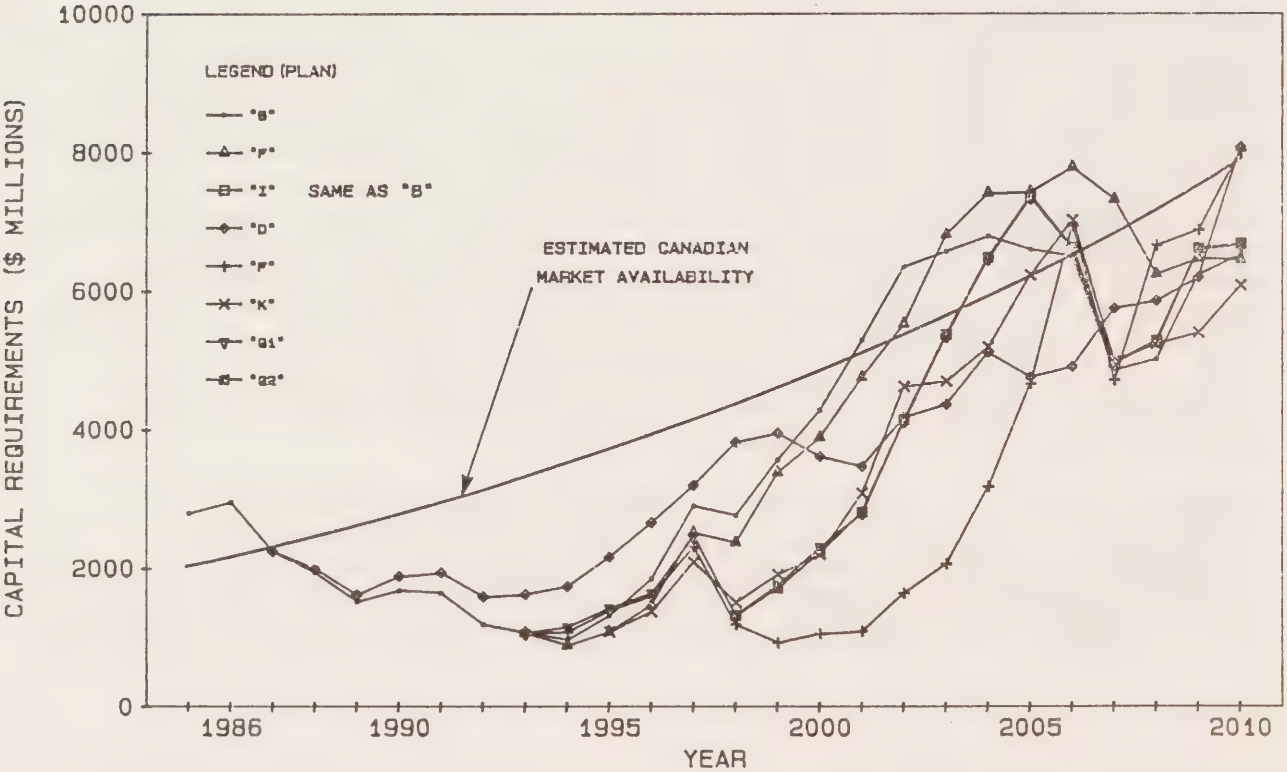


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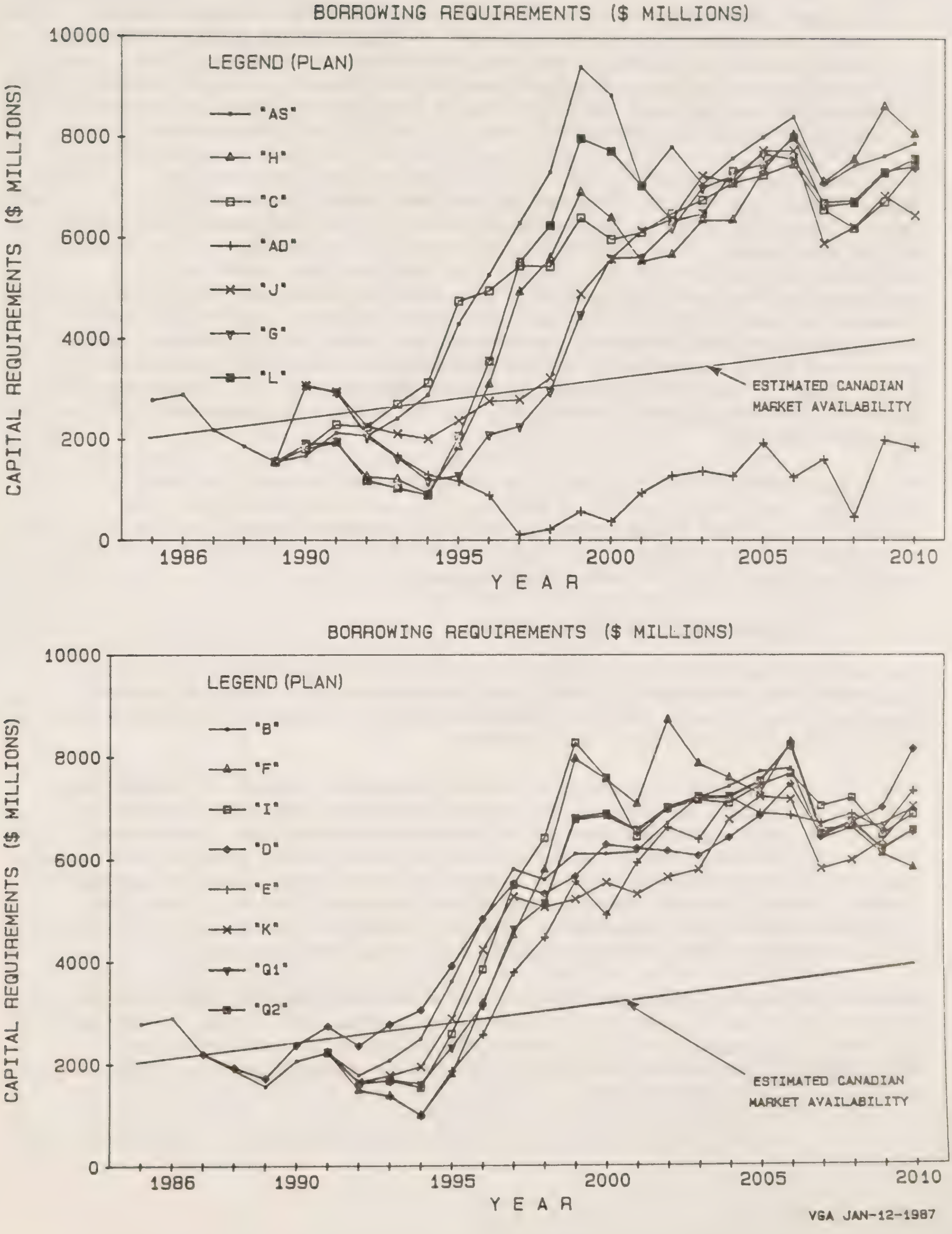
FIGURE 6.8
UPPER LOAD GROWTH PLANS



6.5 Environmental Impacts

All the plans (with the exception of the plans which rely on fossil plant) are expected to be manageable, and the effects on the environment can be made to conform to existing government regulations. The exception in the case of strategies based on fossil plant is because, as described in Section 6.2, in the upper load growth scenario, it may not be possible to keep within the regulations in the longer term.

An attempt has been made to quantify the amounts and type of land requirements, the volume of emissions and wastes and the potential for social disruption associated with each strategy. By and large, the impacts on the environment of the various strategies are reflective of the amount and nature of the generation technologies used and the amount of transmission required. In general the tradeoffs to be made are those between the technologies being used; between the risks inherent in demand management (possible decreased residential air quality) vs. central energy production (land requirements and emissions to air and water); between social impacts vs. environmental impacts; between nuclear (concerns such as long term fuel management) and fossil (possible acid gas emissions, CO_2 and miner safety).

The comparison is between plans or strategies that are more or less acceptable, not between totally unacceptable and totally benign. The analysis gives some extra indications of the physical impact on the environment, and a sense of how easy, or difficult, it will be to get approvals required to implement the strategy.

6.5.1 Transmission Issues and Impacts

The bulk transmission requirements to incorporate new generation and/or purchases were evaluated by examining the province on a regional basis. Expected flows between regions were calculated to determine when and where new transmission facilities were required.

The factors involved in assessing the environmental impacts of transmission are social, technical, natural environment and land-use. The problems associated with social acceptance of overhead transmission lines is not likely to diminish. Public pressure will increase to use undergrounding and where this is not feasible or too costly, to consolidate lines on existing rights-of-ways, expand rights-of-way or to use other rights-of-way, for example railways, where possible. Present technical limitations will have to be overcome before adequate consolidation could be realized.

Currently, Ontario Hydro owns few sites for new major generation stations. Most of the sites it owns are on Lake Ontario, east of Toronto. Development of these sites would lead to a geographic mismatch of load and generation. This mismatch could be significantly reduced by using a few new sites in other areas of the province.

The ease of gaining approvals for these sites and the associated transmission will vary depending on the specific location. In general it is easier to obtain approval for a project in the north (Northwestern and Northeastern regions) than it is in the south. Compared to the north, the increased human settlement, potential impacts on agricultural land, high potential resource areas and visual impacts in the south account for this. Approval for transmission facilities associated with generating stations are rated as being very difficult. It is essential therefore that the approvals for a generating site and associated transmission facilities be carried out in parallel. Moreover in those cases where facilities required for the upper load growth parallel facilities required for the most likely load growth, provision should be made for these parallel facilities in the early stages.

Plans which require fewer generation stations in general require the least transmission facilities, and are the best from a environmental perspective. Distributed resource plans may be slightly better than all demand plans when only the transmission aspects are taken into account. However, when full account is taken of the infra-structure required to service and fuel the many sites of the distributed resource plans, these plans are expected to be no better than other plans which rely on fossil generation. The all demand plans require some long transmission components, but these are less controversial and approvals are assumed to be more readily obtained.

Plans with moderate demand management require significantly more transmission in the forecast case than those plans with high incentives. The difference is less marked in the upper case. The all supply plan is noticeably the worst particularly since lead times require the construction of larger amounts of generation east of Toronto, making worse the geographical mismatch of load and supply. It requires the by-pass across Toronto. The implications of siting generating plant in southwestern Ontario instead of on existing sites on Lake Ontario in order to avoid the need for the by-pass will have to be evaluated.

6.5.2 Generation Impacts

In so far as was possible, without considering site-specific environmental data, assessments were made of the impact on the natural environment of building the required generation resources and operating these and the existing generating stations. The assessment covered the quantities of solid wastes (especially those resulting from acid gas removal), in relation to the land areas required for their disposal or storage; land or resource requirement for new generation sites, including flooding requirements for new or redeveloped hydroelectric stations; consumption water and cooling water volumes; and air quality effects which considered particulate emission levels and the residual SO_2 and NO_x effects.

The predominant environmental concern related to the type and quantity of generation is that related to acid gas emission control. There will be minor variation in the amounts of used nuclear fuel, land requirements and aquatic emissions, but the management of acid gas will give rise to significant differences.

As described in section 6.2 all the plans, with the possible exception of fossil based plans in the upper scenario should be manageable. However, the level of effort required could be significantly different. Taking the total effort required over the time period, then the high incentive demand management plans and the nuclear strategies are the least trouble. Strategies heavily dependent on fossil generation are the worst. These rankings are more or less independent of load growth.

6.5.3 Social & Community Impacts

The social and community implications of the representative plans were evaluated with respect to: regional employment and development, community impacts of projects and programs, special interest impacts, and distributive impacts or the equitability of the distribution of costs and benefits. The assessment identified the distributed resource plan with moderate demand management incentives as the preferred representative plan due to the opportunity to distribute regional employment and development benefits, reduced transmission impacts, and the fact that with distributed resources both the costs and benefits of regional electricity generation will be felt within the region and shared more equitably among regions of the province.

The assessment also identified a number of social and community concerns that cannot be accurately measured at this stage of the planning process.

These include:

(1) The impact of demand management programs on the individual consumer and the extent to which benefits and costs of demand management are equally shared by all customers across the province.

(2) The implementation of each technology alternative will generate unique sets of special interest issues, the nature of which depends on details of the technology and its implementation.

(3) There can be tradeoffs between opportunities for major regional employment and development benefits and provincial economy benefits.

(4) Different options require different employment skills and employment "ownership" (ie. Hydro or non-Hydro).

These issues are significant and will need to be addressed throughout the planning process as additional information becomes available.

6.6 Provincial Economy Impacts

The preferred plans are those that have the maximum amount of demand management.

The impact on the provincial economy cannot be simply gauged by the average cost of electricity. This is because conservation releases customer cash for other purposes. To maximize economic benefit, the efficiency with which the provinces resources are used is important. The ideal plan from the provincial economic perspective has as much value-added in Ontario as possible with the minimum of negative consequences for rates or capital markets. The latter have been discussed in Section 3.3 and 6.4.

In general, the plans with high incentive driven (marginal cost) conservation followed by a supply option (nuclear or fossil) has the most favourable impact on the provincial economy. Plans that rely on energy efficiency improvement measures followed by price induced demand reduction do relatively well during the 1986 to 2009 study period, but given the performance of the all-price plans, are expected to fall in the ranking after 2010. Similarly, plans with fossil plant do relatively well in the 1986 to 2009 period, but are expected to fall in ranking after 2010 as a result of their continuing high operating costs.

The plans which emphasize energy efficiency do well because these expenditures have higher Ontario value-added and re-spending effects than capacity expansion expenditures. Supply dominated plans were in general superior to purchase plans which suffered from low value-added in Ontario. The lack of Ontario activity involved in generating the electricity is not sufficiently compensated for by the lower electricity rates. Plans with nuclear are preferred to those with coal. This preference appears to be independent of the level of demand management activities.

A ranking of the plans, under forecast load growth conditions, in terms of the impact of real Gross Domestic Product and employment is given in Table 6.9.

The effect of Ontario Hydro's borrowing crowding out other investment has been considered in these calculations. It doesn't make a significant difference to the ranking of the plans.

The best plan appears to be that which takes the maximum amount of demand management and then follows with nuclear. The analysis of the options indicated that demand management and the nuclear had similar impacts on the provincial economy. The preference shown in the plan analysis for demand management comes from two factors. Firstly, the demand management is brought into service earlier than new nuclear stations. Secondly, the impacts of the new nuclear plant have only been assessed up to 2010. Nuclear plant would continue to give benefits for another thirty years or so, the efficiency improvement measures would soon have to be replaced since they generally have shorter lives and have been in service longer. Thus, if the plan analysis was extended, the two options would have more similar benefits.

Figure 6.9

Economy-Wide Impact (Most Likely Load Growth)
(N.P.V. 1986-2009)
(Difference and Percentage of Plan B)

TOTAL G.D.P.
(Millions 1985$)

PLAN		
J	6653	5.47%
G	6341	5.21%
AD	5527	4.55%
D	1575	1.30%
B (level)	121601	
I	0	0.00%
F	-330	-0.27%
AS	-508	-0.42%
K	-540	-0.44%
L	-944	-0.78%
Q2	-1179	-0.97%
C	-1715	-1.41%
E	-2349	-1.93%
Q1	-2960	-2.43%
H	-3201	-2.63%
P2	-13762	-11.32%
P1	-13792	-11.34%

TOTAL EMPLOYMENT
(Person Years)

PLAN		
G	91197	5.88%
J	84276	5.43%
AD	78346	5.05%
K	18713	1.21%
L	18135	1.17%
D	8364	0.54%
E	3392	0.22%
F	3073	0.20%
B (level)	1551866	
I	0	0.00%
Q2	-1622	-0.10%
C	-4406	-0.28%
P2	-4482	-0.29%
H	-4822	-0.31%
AS	-15389	-0.99%
Q1	-21637	-1.39%
P1	-22777	-1.47%

Note: Results are quoted as the G.D.P. or employment generated in the plan minus that produced in plan B.

The impact of these purchase plans which delays nuclear was done under two assumptions of contract price. The economic impact of all-price plan was analysed under two different assumptions of respending the electricity tax revenue raised by the government. These two cases were used because there is some uncertainty about the modelling of the response of the economy to large electricity rate shocks.

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7.0 CORPORATE HUMAN RESOURCE ISSUES

Total staff levels are not a consideration in choosing a plan. Even with the many differences between the plans, they require similar total levels of staff in the short term.

> High incentive demand management will require a rapid buildup of manpower in Marketing and the Regions.

High incentive demand side management programs would require additional marketing resources (300) to deliver the program and this could be difficult to accommodate within Marketing & Regions Branches in the short term. This would be especially marked if it was decided to hire sufficient staff to be able to deliver a crash program, such as might be needed if the load growth followed the upper scenario. However, these numbers are insignificant compared to those required for supply options.

Potential Design and Construction Branch difficulties arise if a construction program is required immediately, it would be hard for the Branch to manage the work required to meet the upper load growth. Problems also arise if it is delayed too long. Orderly plans are in the Branch's best interests. Figure 7.1 shows why. It shows the manpower requirements in the absence of any smoothing, for three first unit in-service dates for the next nuclear station. Figure 7.2 lists the relative advantages of these in service dates from the perspective of the three groups involved.

Potential Production Branch difficulties centre around plans which call for the rapid rehabilitation programs. Unfortunately these are required in all upper load growth scenarios, though adoption of heavy demand management strategy would ameliorate the situation.

From the human resources perspective a "mixed" strategy is a must. Of the mixed strategies, an orderly program, would be preferred.

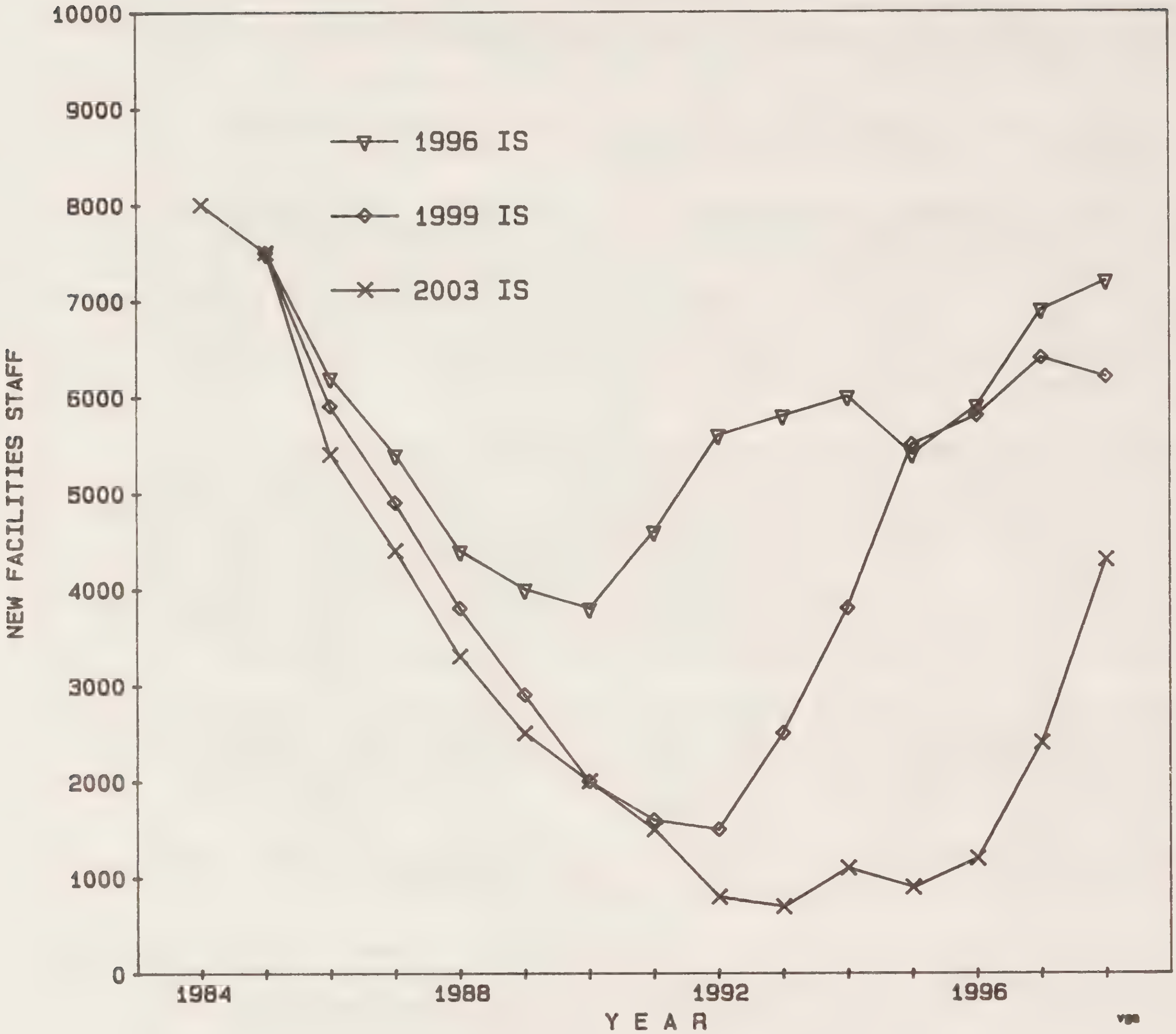
If a strategy is not chosen, or if the decision is to defer any decisions but the flexibility to choose any option is maintained, the staff levels required will exceed those of any individual alternative and therefore become an issue. Also maintaining staff morale will be difficult.

8.0 COMPARISON & RANKING OR REPRESENTATIVE PLANS

> No plan clearly out-ranks the others in all aspects of the evaluation discussed above.

A multicriteria analysis considered seven of the representative plans. The following evaluation factors were used: financial (long run economics, customer costs, borrowing levels), environmental (generation and transmission-related), and socio-economic (community impacts, Provincial economy impacts on Gross Domestic Product and employment). The impacts of the plans on these factors were considered in the most likely and upper load

FIGURE 7.1
DESIGN & CONSTRUCTION STAFF REQUIRED
FOR NEW NUCLEAR STATION



Note: Graph is based on data developed in 1985.

FIGURE 7.2

D&C: HUMAN RESOURCE IMPLICATIONS

FIRST UNIT IN-SERVICE DATE	DESIGN ENGINEERING	FIELD ENGINEERING AND CONSTRUCTION
2003	. 4 YRS DOWNSIZING . VERY SMALL BASE . HIGH BUILD UP RATES . CONCERN RE MAINTENANCE & ACQUISITION OF STAFF . CONCERN RE CONSTRUCTION TRADE AVAILABILITY	. 9 YRS DOWNSIZING
1999	. NEED STAFF NOW . NEEDS IMMEDIATE CHANGE IN DIRECTION	. 5 YRS DOWNSIZING . REDUCED CONCERNS
1996	. BEHIND SCHEDULE	. SOME DOWNSIZING

growth scenarios. It should be noted that several aspects, such as flexibility, diversity and public attitudes were not considered in this analysis.

Although no single plan is better than all the others on all factors, some plans are preferred when specific evaluation factors are emphasized.

If financial implications are considered most important, then the preferred plans are those oriented towards nuclear supply (B,D,Q and AS).

If socio-economic considerations predominate, then the preferred plans are those with high demand management incentives (G and J).

If avoiding environmental impacts is emphasized, then plans with high levels of demand management and minimizing the use of fossil plant are preferred (Plan J).

Figure 8.1 shows the ranking (0 best, 5 worst) of the seven representative plans in the multicriteria analysis.

Figure 8.1

RANKING OF REPRESENTATIVE PLANS

Plan	Predominant Evaluation Factor		
	Financial	Socio-Economic	Environmental
AS All Supply-Nuclear	3	1	0
J Max Demand & Nuclear	2	4	5
G Distributed & Fossil	0	5	3
B Mixed (Nuclear)	4	1	2
D Mixed (Nuclear-smoothed)	5	1	3
K Mixed (Fossil)	1	1	2
Q Mixed (Purchase & Nuclear)	4	0	3

5 = best 0 = worst

The All Supply (nuclear) plan AS is least preferred due to environmental and socioeconomic drawbacks. Plans with high levels of demand management (J & G) are preferred on socio-economic and environmental grounds. The distributed plan (G) is, however, least preferred plan if financial considerations predominate.

Comparing nuclear and fossil, the results reflect the fact that nuclear is financially and environmentally preferred.

There are advantages in developing nuclear capacity early. The mixed smoothed nuclear plan D (if it could be realized) is preferred to the mixed nuclear Plan B, regardless of which factors are considered most important. However, it is more at risk to lower load growth, a factor not considered in this analysis.

9.0 KEY MESSAGES FOR STRATEGY

Demand management can make a substantial contribution to the demand/supply balance and delay the need for acid gas control measures. It is economic both to Hydro's customers and to the provincial economy. However, the identified potential suggests that it cannot be relied upon to meet all the needs. Market demonstrations are required as soon as possible to reduce the uncertainties surrounding its contribution and so that efficient delivery programs can be put in place in time to delay the need for new supply facilities.

Independent generation and hydraulic generation can make a contribution but will only meet a small part of the resource requirement.

Nuclear plant can meet expected needs for major energy producing plant while minimizing costs, avoiding acid gas control emissions, and with acceptable financial impacts. Nuclear options are constrained by long lead times.

Fossil plant is not a preferred source to meet expected requirements, but is an important option in light of its shorter lead times and the possibility of higher than expected load growth.

There is a need to start planning activities based on a higher load growth to provide a high degree of certainty of meeting demand with low cost resources.

10. REFERENCE REPORTS

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Financial Impacts of Representative Plans. BESR 8702, January 1987.

Sensitivity & Risk Analysis of the Representative Plans. BESR 8703, January 1987.

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Assessment of Alternative Plans: Social and Community Impacts.

Analysis of Representative Plans: Environmental Impacts-Generation.

The Optimal Level of Planning Activity. BESR 8704, January 1987.

A Multicriteria Assessment of the Representative Plans. BESR 8705, January 1987.

A Discussion of the Resource Diversity of the Representative Plans. BESR 8706, January 1987.

Appendix A

THE REPRESENTATIVE PLANS

SUPPLY PLANS

These plans illustrate the effect of no demand management except the existing interruptible load. All these plans have Lakeview rehabilitated, 6 or more hydro electric developments and some cogeneration.

Nuclear

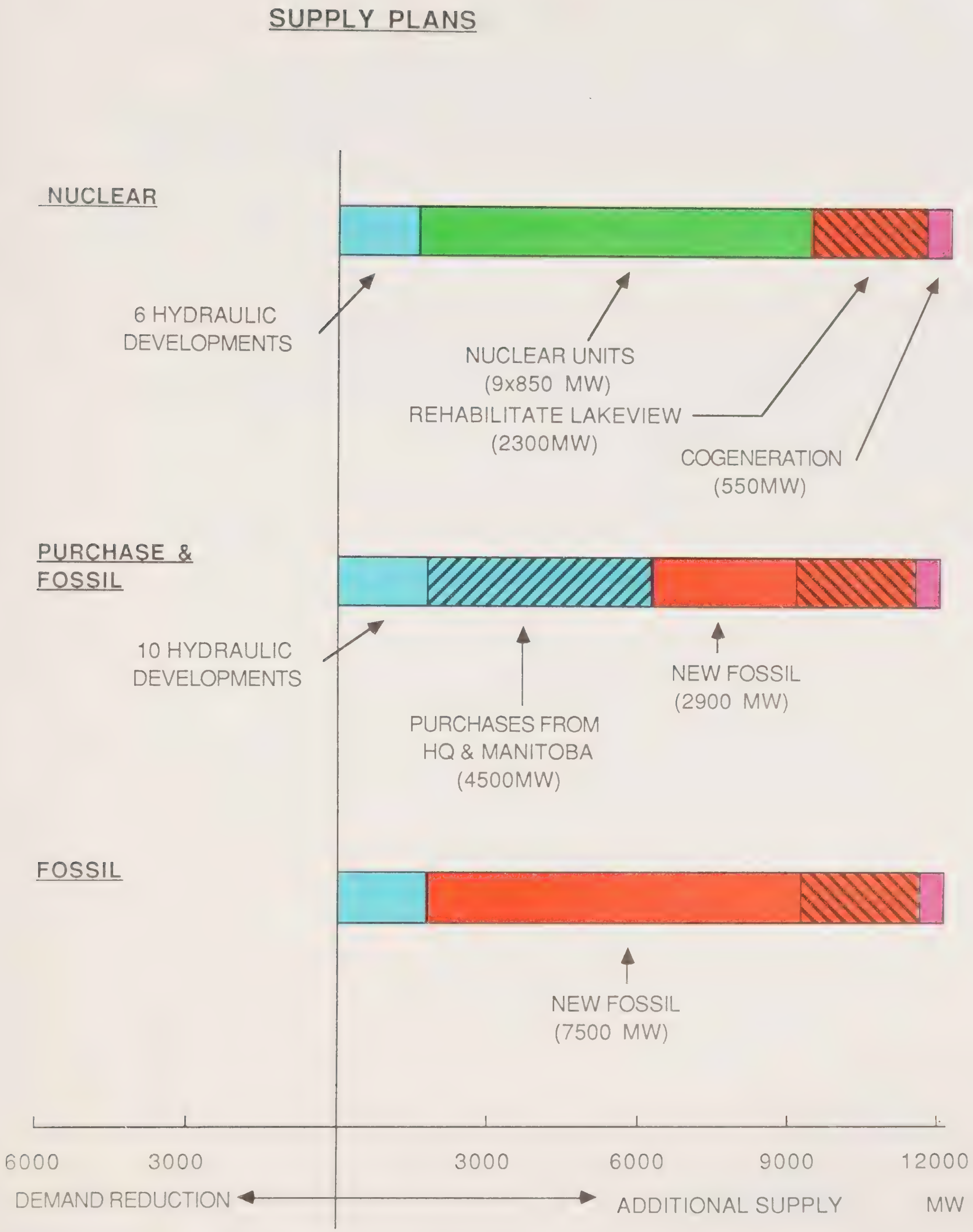
The bulk of the requirement for new plant is made up of nuclear with earliest in-service date of 2000 because nuclear is the least cost major supply source. New sites for nuclear plant will likely be required in Northern Ontario and Southwestern Ontario.

Purchase and Fossil

If new nuclear is not acceptable, the requirements for new plant could be met by purchases from Hydro Quebec and Manitoba, starting in 1997, growing to 4500 MW by 2006. Beyond 2005, new fossil plant will be required.

Fossil

This is a supply plan based largely on fossil additions. Additional hydroelectric delays the need for fossil plant to the year 2000. This program has the greatest risk of being unable to meet acid gas emission regulations.



ADDITIONAL RESOURCES BY 2010 MOST PROBABLE LOAD GROWTH

DEMAND PLANS

These plans illustrate the effect of relying primarily on demand management. In both cases, it is assumed that to obtain maximum penetration, Ontario Hydro would pay the full costs of economic conservation measures, even though this would increase electricity rates. These plans have 1500 MW of load shifting and 4100 MW of load reduction due to improved electrical efficiency.

It is also assumed that increased incentives will be paid for private generation and that there will be an additional 1200 MW by 2010.

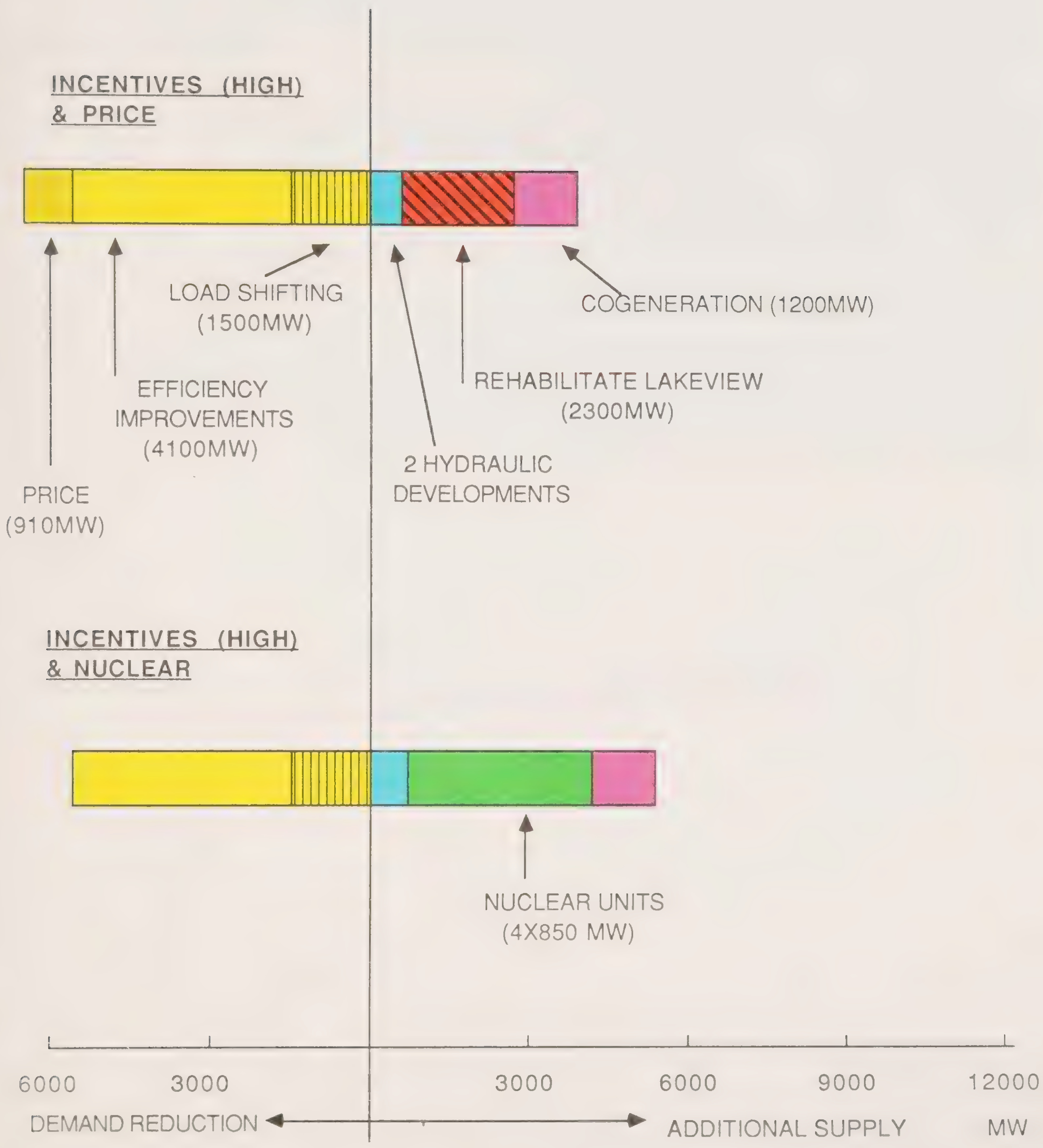
Demand Plan - Price

The above measures are inadequate beyond 2007. This plan achieves further demand reduction by raising the price for electricity. This requires an increase of about 10% above costs by 2010. In a higher load scenario, the increase must be 100-200%.

Demand Plan - Nuclear

This plan examined the effect of following the least cost supply option, nuclear, once economic demand resources are exhausted. The first nuclear unit is required in 2006.

DEMAND PLANS



ADDITIONAL RESOURCES BY 2010- MOST PROBABLE LOAD GROWTH

DISTRIBUTED RESOURCE PLANS

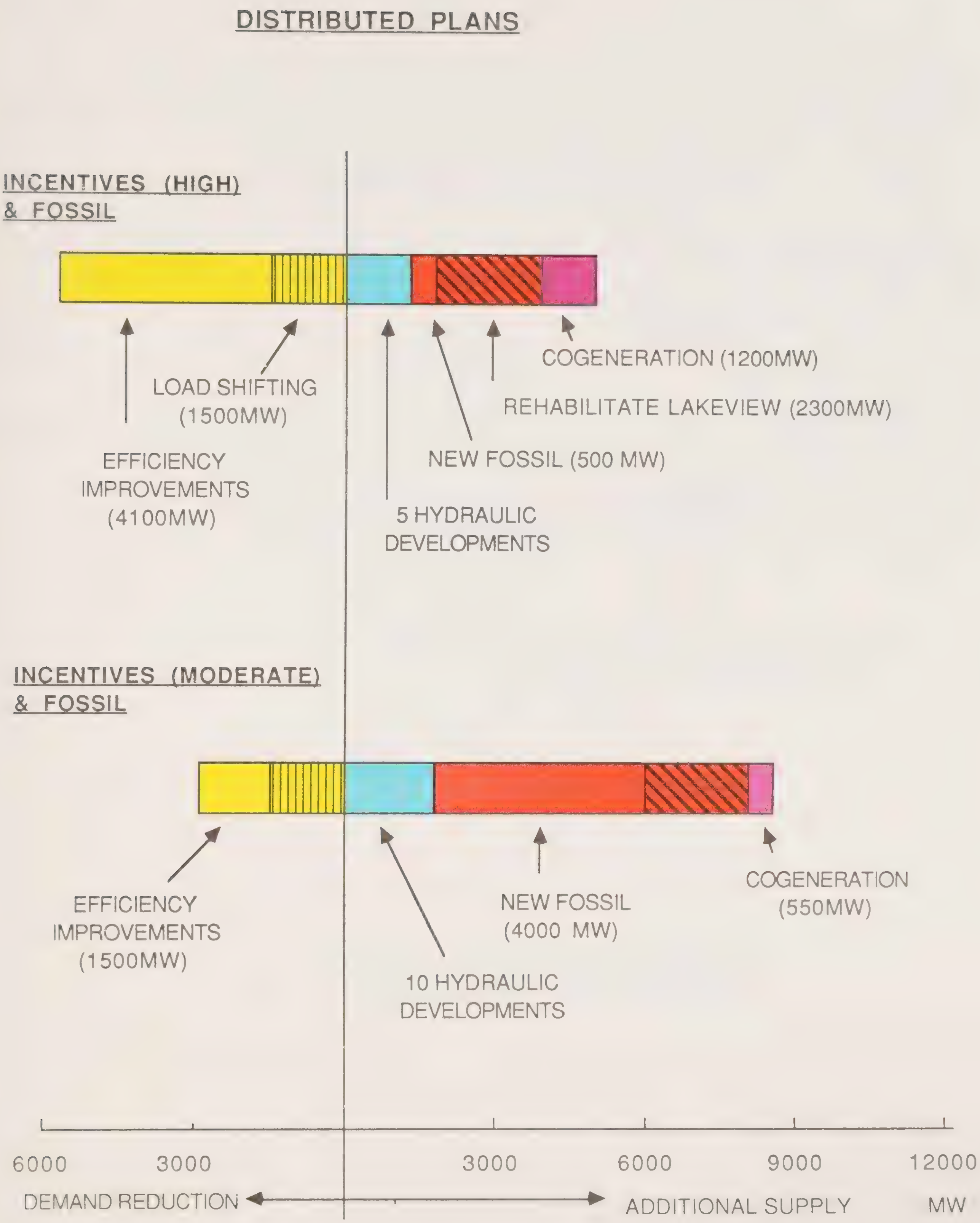
These plans minimize the need for additional bulk power transmission by matching the geographic distribution of resources to the geographic distribution of load. Most of the bulk power transmission planned before the year 2000 is still required. Nuclear plant is not included in these plans because small plants (200-500 MW) are required to match load without new bulk power transmission.

Distributed Resources - High Incentives

This plan is similar to the Demand Plans. Ontario Hydro pays the full cost of economic efficiency improvements and increased payments for private generation. Customer equity is assumed to be a secondary issue. Towards the end of the period, it is necessary to start building small fossil-fuelled plants.

Distributed Resources - Moderate Incentives

Incentives for efficiency improvements are limited to about 50% of the cost. Payments to private generators are based on avoided cost. Starting in 2002, small fossil units are required, building up to over 4000 MW by 2010. This plan generates the problem of finding sites for fossil plant in the Central Region area where most of the load growth will occur.



ADDITIONAL RESOURCES BY 2010 - MOST PROBABLE LOAD GROWTH

MIXED PLANS

These plans all rely on the demand management that can be achieved with a moderate (about 50%) level of incentives. This level of incentive avoids most of the increase in electricity prices that would result from 100% incentives. Rates for private generation are based on avoided cost.

Nuclear

Based on least cost, the supply requirement is largely met by nuclear plant starting in 2002, rising to over 7000 MW by 2010. At least one new site for nuclear will be required probably in Northern Ontario. The next page describes variations to this plan depending on when approval and construction work is initiated.

Purchase and Fossil

If nuclear is not acceptable, this plan shows the effect if 2500 MW of purchases is available that is competitive with coal. The first 500 MW of purchase is acquired in 1997 (approximately 4 years ahead of need).

The purchase, together with increased hydraulic development and rehabilitation of Lakeview defer the need for new fossil plant to 2007.

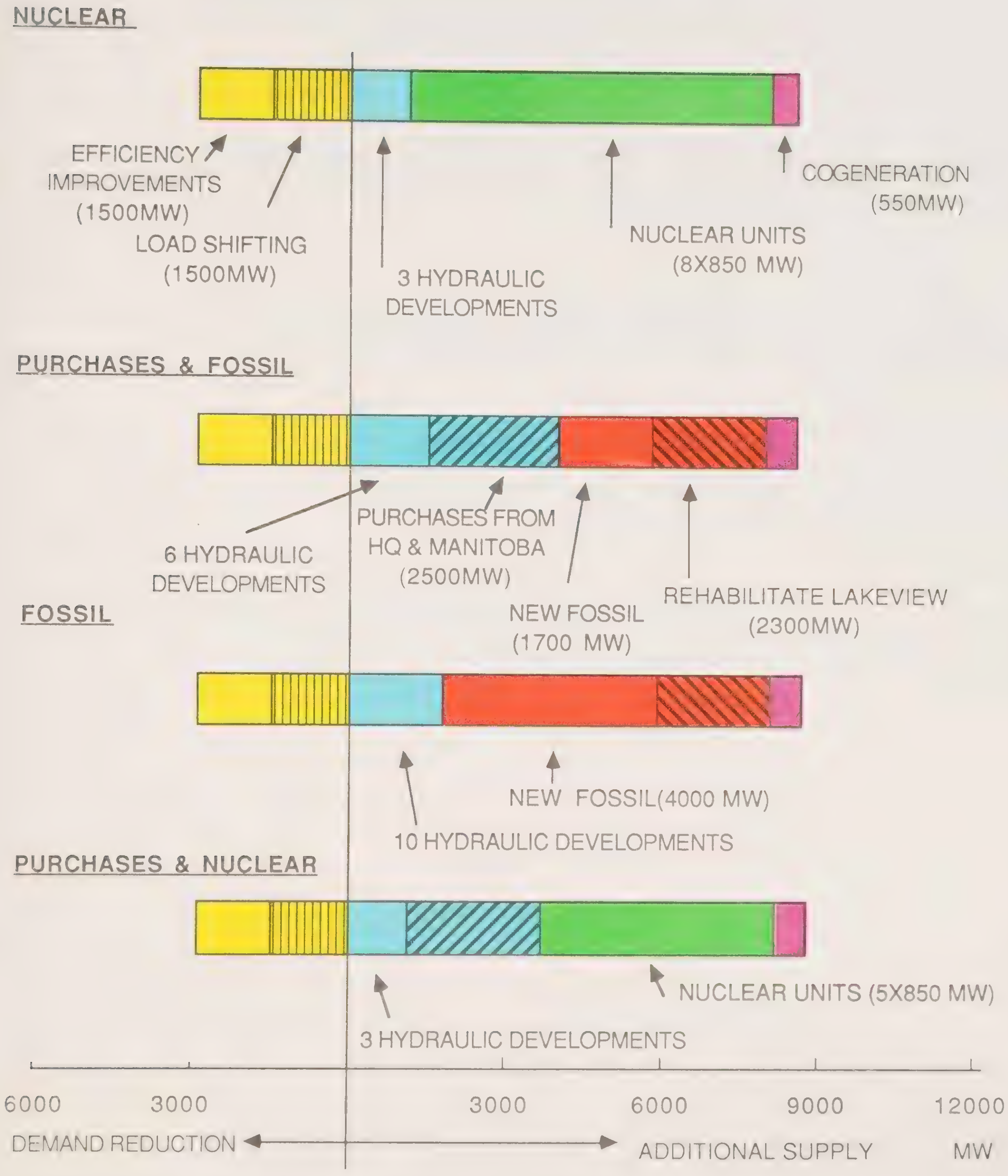
Fossil

If nuclear and cost-effective purchases are not available, the bulk of the new supply must be provided by fossil-fuelled plant. Early hydraulic is used to defer the need for the first new coal plant to 2002.

Purchase and Nuclear

In this plan, purchases growing to 2500 MW meet the bulk of the need from 1998 to 2005. Nuclear is used after purchases since it is the lowest cost major supply option. The first unit is required in 2005.

MIXED PLANS



ADDITIONAL RESOURCES BY 2010 - MOST PROBABLE LOAD GROWTH

FLEXIBILITY VARIATIONS TO MIXED PLAN - NUCLEAR

An important decision factor is when to start approval and construction phases for new plant. This is particularly important in plans that use nuclear because of the long lead times. The differences tend to show in the flexibility to adapt to possible but less probable futures.

With Flexibility

Start environmental assessment (EA) processes early to give a measure of protection against high load growth - apply for nuclear plant, or fossil if nuclear is not acceptable. EA's started in 1988 for two new plants and one new generating station site.

Delay Decisions

Delay E.A. process for major supply options to 1992. Build more small hydroelectric plants (2000-2005) to bridge gap before first nuclear comes in-service in 2004.

Limited Flexibility

Start E.A. process for one nuclear plant two years earlier than required under most probable load growth (1988). Start E.A. process for one nuclear generating station site.

Smoothed Program

Advance and accelerate approval processes to achieve a 1997 in-service date for the first new nuclear, to smooth requirements for resources and to sustain the Canadian nuclear industry. This may also be economic in the long term.

DRAFT DEMAND/SUPPLY PLANNING STRATEGY

SUPPLEMENTARY DOCUMENT G

STRATEGY IMPLEMENTATION - AN ILLUSTRATIVE PLAN

December 1987

System Planning Division

Table of Contents

1.0 INTRODUCTION

A Demand/Supply Planning Strategy is an indispensible base on which future energy needs must be built.

This document assumes such a strategy is in place. It also assumes the current processes for planning and approvals of programs and projects. The document illustrates the direction energy supply and demand could take and describes the programs and projects that could flow from the draft planning principles.

The examples extend to the year 2010. Plans and programs to the year 2000 are more specific. To reflect the longer term uncertainties after 2000, the document outlines ranges rather than specific numbers.

The implications of different load growth trends (most likely, upper and lower) are examined separately to demonstrate the flexibility to respond to changing trends.

The final section concentrates on the short-term program of work to complete projects underway, to maintain the existing system and to start implementing the strategy. Activities in the short-term program are designed to meet the most likely load growth and respond to higher or lower trends which could result from future technical, economic and social changes.

2.0 PLANNING FOR THE MOST LIKELY GROWTH

For the December 1986 load forecast, the most likely growth rate is about 2.4 percent a year. This requires the equivalent of 10,000 MW of additional capacity, whether demand management or new supply, in 2010. (See Table 1).

2.1 Existing and Committed System - Year 2000

Darlington, a 3,600 MW nuclear station, is the only generating plant now being built by Ontario Hydro. It is scheduled for completion in 1992 with the first of four units in-service in 1989.

The draft strategy places high priority on maintaining and improving the performance of existing facilities (Consideration 5.5.1)*. The coal-fired Lakeview GS will reach its designed operating life of 30 years in 1996. In addition, its performance has deteriorated in the last few years.

Rehabilitating Lakeview is expected to be cheaper than other supply options in the 1990s. An inspection program is underway to determine the needs and costs of extending Lakeview's working life to restore adequate performance and make the station's 2,400 MW available to 2006. Running the station after 2006 would depend on additional work needs, costs and other options available at the time.

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* Numbers correspond to the strategic considerations listed in Chapters 11 and 12 of the main report.

The oil-fuelled Lennox station (2200 MW) will be needed by 1999. The station was mothballed in the early 1980s. In 1987, two of the four units were returned to service to maintain system reliability and meet seasonal peak loads. A decision will be made closer to 1999 on whether to convert Lennox to natural gas or coal fuel or leave it as an oil burning station. The amount of usage and cost will be the deciding factors.

Many of the hydraulic generating plants are more than 50 years old and will need increasing maintenance, rehabilitation or possibly redevelopment.

The mothballed Hearn and Keith fossil fuelled stations, more than 30 years old and expensive to run, could be rehabilitated and returned to service should load growth be much higher than expected (Consideration 5.5.3).

To meet acid gas emission limits while making full use of the existing system, a major emission control program would be needed, including scrubbers and more low sulphur coal. By 2010, depending on choices for new base load generation, scrubbers or equivalent measures would probably be needed on up to 8,000 MW of fossil generation; essentially all major coal-fired capacity. The first scrubber, or equivalent, will likely be needed in 1994 with 3,000-4,000 MW scrubbed by the year 2000. The amount of electricity generated from coal in the 1990s also depends on load growth (see Section 3) and the success of demand management. These factors will affect the number and timing of emission controls.

With additions and improvements, Ontario Hydro will have a generating capability of 32,400 MW which is able to meet a peak demand of 26,000 MW after allowing for a reserve margin (Chapter 5, main document). Based on the December 1986 forecast, a load of 28,600 MW is expected by the turn of the century and 34,000 MW by 2010.

Plans to meet the load in 2010 are described below. New resources may be needed to replace existing plant that have reached the end of their useful life.

2.2 New Demand and Supply Resources

This section examines demand management, electricity purchases from independent Ontario suppliers, hydraulic generation, additional base load supply, building new plant or firm, long-term purchases and transmission requirements.

2.2.1 Demand Management

Defined as actions to influence the amount or timing of electricity use by customers, demand management concentrates on two broad techniques. First, load shifting which seeks to move electricity use from peak to off-peak periods mainly by offering rate incentives. Second, efficiency improvements such as heat pumps, better insulation, more efficient motors, and improved ventilation and lighting systems.

Considerable uncertainties remain about the effects of the options due to the wide range of social and economic variables. Table 1 reflects the uncertainty by listing ranges rather than specific amounts. However, successful demand management programs can reduce and defer the need for additional supply.

To reduce the uncertainties, the strategy encourages an early start to demonstrate and develop demand management programs (Consideration 3.5.1). It is a slow process. The demonstration programs, which look at cost effectiveness and implementation, will take several years. It is expected to take about a decade to achieve high levels of penetration for any of the programs.

Considerations 3.1, 3.9.1, .2, .3, outline the size of incentives; the contribution of customers who benefit and acceptance of incentive levels by general customer groups.

For this document, the demand management program is based on a moderate incentive level (50 percent of the program costs). Implementation would start around 1990 so the programs would make a substantial contribution by the year 2000.

(A review of demand management options is contained in Supplementary Document C.)

Although the level of load-shifting is limited (Consideration 3.2.1), it could result in the shifting of 500 to 1000 MW by the year 2000 and another 300-500 MW by 2010 (Table 1).

Table 1 also shows efficiency improvements contributing from 400 to 2250 MW by 2000, with an additional contribution of 200 to 750 MW by 2010. (See Chapter 8.1.1 for a discussion of efficiency improvements).

2.2.2 Independent Generation

The purchase of electricity from independent producers is based largely on avoided system costs, what it would cost Ontario Hydro to manufacture and deliver the same amount of electricity under similar conditions (Considerations 4.1, .2, .3, .4, .5).

It is expected that independent generation will contribute 300-1000 MW by 2000 and another 200-440 MW by 2010. The ranges are wide because, like demand options, there are wide uncertainties on how much generation will be induced by a given level of incentives.

Some of the independent generation would use indigenous fuel, wood waste or water. However, much of the potential would use scarce imported fuels which raises concerns about long-term supply at reasonable prices (Considerations 2.4.1, .2).

2.2.3 Hydraulic Generation

Table 1 shows 1100-1300 MW of new hydraulic generation by 2000, on the Little Jackfish, Mattagami and Niagara Rivers. Little Jackfish, a new site, can help reduce energy costs in northwestern Ontario. The Mattagami redevelopment plans include additional generating units in the three Hydro stations now operating and purchase and redevelopment of Smoky Falls GS, owned by Spruce Falls Power and Paper.

Niagara River redevelopment is at an earlier planning stage. The intent is to replace a retired and aging generating plant with a more efficient new station on a different site that takes better advantage of water flow.

Studies of other sites will likely yield additional economic opportunities. An additional 600-1000 MW of economic hydraulic development is included by 2010. A small part of this amount could possibly be completed by 2000.

The strategy calls for the orderly development of economic sites to match system requirements and provide a steady program of developments (Considerations 5.7, 2.3).

2.2.4 Additional Base Load Supply

The estimate of additional base load supply is 1000 MW to 5000 MW by 2010, with first in-service dates between 2001 and 2006. The range, even for the most likely forecast, reflects a number of uncertainties:

- Effectiveness of demand management programs;
- Amount of economic supply from independent producers;
- Extent of new hydraulic generation;
- Economies of extending the life of Lakeview GS beyond the study period.

Choices for additional base load are new coal, new nuclear and electricity purchases from neighbouring systems. The strategy calls for the lowest cost options after demand management and independent generation make their contributions (Consideration 5.1).

However, other factors must be weighed:
- Currently, nuclear costs less than coal;
- Nuclear is an indigenous resource (Consideration 2.4);
- Options must be socially and environmentally acceptable (Consideration 1.4);
- The level of public acceptance of the available demand and supply options.

If the choice is largely coal, acid gas emission controls and sludge and ash disposal become increasingly important. More controls will be needed at existing stations (upper-range Table 1) with leading edge technology used at new plant (Consideration 5.8).

The selection of nuclear plants could contribute to lower long-term costs, using low cost indigenous fuel. The main nuclear issues are safety and used fuel disposal.

Long-term firm purchase of hydraulic power is an acceptable option (Consideration 6.2). The amounts needed would require construction of new plants in Quebec or Manitoba and the associated transmission systems. The process is as lengthy as building new generating facilities in Ontario and the need for binding agreements early in the process can lead to inflexible commitments earlier than with other options.

Higher cost options (eg, fossil) would justify higher incentives for demand management and higher rates for independent generation, bringing both closer to the upper end of their ranges. More hydraulic development would become economic. The result, however, would be a higher-cost system.

2.2.5 Transmission

New transmission lines and stations have been approved for eastern and southwestern Ontario. Improvements are planned in northern and southern Ontario. This base transmission system is essential for all plans, regardless of load growth and the success of demand options.

Additional transmission will be needed to connect new generating stations, strengthen system security and supply growing demands. For the illustrative plan under the "most-likely" forecast, a new high-capacity East-West interconnection would be needed between Sudbury and Thunder Bay and reinforcement of interconnections between Sudbury and Toronto may be needed, depending upon the base load supply option chosen.

3.0 VARIATIONS FROM THE "MOST-LIKELY"PATH

Considerations 2.2.1 and 2.2.2 outline the need to plan for a reasonable range of variation in load growth estimates. This section examines the implications of upper and lower growth (Tables 2 and 3).

The examples assume initial plans and programs develop on the most-likely path. At a certain point, the new load path is recognized and adjustments made. The reality is that a changing trend would be recognized over a number of years and planning would evolve to meet the changes. However, for discussion, the year 1991 has been selected as the adjustment point.

The information in Tables 2 and 3 goes only part way toward developing contingency plans (Consideration 2.2.2). The plans are not yet fully developed. While considerations of upper and lower load growth may lead to variations in the short term work program to provide increased flexibility, commitments to implement demand options and build supply options will be based on the most likely load forecast at that time (Consideration 2.2.3).

3.1 Upper Load Growth (Table 2)

Under this scenario, providing sufficient capacity will be difficult. Because of the time factor, the priority is availability rather than economics.

Maintaining and improving the existing system becomes more important (Consideration 5.5.1). Lakeview would have life extensions to enable it to run throughout the study period. Hearn and Keith are assumed to have been maintained in a preserved state (Consideration 5.5.3). These plants would need to be rehabilitated and returned to service. Lennox, on a year round availability basis, would require restarting of the remaining two units early in the 1990s.

A major scrubber retrofit program would be required with the first needed as early as 1992. However, with the lead times and the current progress of the preliminary work on scrubbers, it would be unlikely that they could be installed in time. Other more expensive measures (fuel substitution and cutting exports) would be pursued until the mid 1990s.

Increased incentives for demand options can be justified because only higher cost supply options are available (Consideration 3.1). Higher incentives would increase the rate of penetration and the total amounts achieved. Although demand management makes a significantly higher contribution than in the most probable case, there still is uncertainty about the effectiveness of the efficiency improvements so the range remains wide. The load shifting options are also increased, since a larger system with a larger load can make effective use of more shifting (Consideration 3.2.1).

As with demand options, higher load growth would justify higher incentives for independent generation (Consideration 4.1). These would be based on the avoidance of capacity shortfalls and the use of higher cost alternatives (fossil) to meet the increases in load.

The hydraulic program would also be extended and intensified to accelerate the orderly development of new sites (Consideration 5.7). Again, compared to the alternatives (fossil), more hydro sites would become economic and would be developed before the year 2000.

After allowing for these demand and supply options, additional base load energy supply will be needed in 1996. About 500-1000 MW would be needed by 2000 with an additional 9,000 to 12,000 MW by 2010. The strategy calls for use of the lowest cost, available supply or purchase options (Consideration 5.1). With the current 13-year lead time, new nuclear would not be available before 2001. Thus, the available supply option in the late 1990s is fossil or possibly purchases because of shorter lead times. Compared to nuclear, conventional fossil has a current lead time of about 10 years. The integrated gasification combined cycle fossil option potentially offers a lead time of about eight years.

The limits imposed by acid gas regulations, mean that coal-fired generation could be used to supply only 4000-7000 MW of additional need, with units starting to come in-service about the year 2000. The balance, to the year 2010, would be met by new nuclear generation, with the first units coming into service in 2001. This much construction would stretch Hydro's capabilities.

Firm purchases would be useful in this scenario. Yet high growth will likely be common across North America, with intense competition for additional supplies.

Because of time constraints, there would be a shortfall about the year 2000 of up to 4000 MW, which could be eased by more expensive demand options and temporary major purchases.

3.2 Lower Load Growth (Table 3)

If the economy stagnates, it could be several years before we recognize a low growth scenario. Once recognized, all preliminary work on new fossil and nuclear supply options would be cancelled. If this were not until 1991, Little Jackfish may be continued to completion because it could be too far advanced to cancel. Niagara may still be built to retain water rights shared with the U.S. However, the Mattagami redevelopments would be cancelled. Darlington GS, already far advanced, would be completed.

While financial incentives would be lower, reducing the rate of efficiency improvements, the market would be encouraged to make wider use of economic supplies. In a stagnant economy, less independent generation would be needed, however, some projects would continue using inexpensive waste products as fuel. No acid gas scrubbers would be required.

Breaking firm purchase commitments made before the low-growth trend could mean cost penalties. Alternatively, purchases could continue while production from Hydro's highest-cost plants would be reduced.

4.0 SHORT-TERM WORK PROGRAM

The path of electricity planning becomes less definite as we look farther into the future. However, the short-term needs are clear. Table 4 lists the type and timing of work required. Programs in many of the areas are already underway.

4.1 Existing and Committed System

The Lakeview plant will need major rehabilitation to extend its useful life beyond 1996. The work must begin in the next few years to stop deterioration. It is a relatively inexpensive process and offers flexibility to meet increases in load growth. An inspection program is underway to assess requirements and costs of extending Lakeview's operating life 10 or more years.

Engineering and economic studies are analyzing the acid gas technology most suited to each of our major coal-fired plants. Costs, technologies, site characteristics and waste disposal methods will determine the most suitable combination. A three year, $7.7 million program has begun to obtain approvals under the Environmental Assessment Act. We want the flexibility to install any of four control devices at any of our three major coal-fired stations within the next 20 years. A detailed environmental assessment document will be submitted to the Ministry of Environment in 1988.

Low nitrogen oxide burners have been installed on all eight boilers at Nanticoke Generating Station, at a cost of about $13 million. This reduces nitrogen oxide emissions by 35 percent.

In addition, studies are examining the use of low sulphur fuels beginning in the mid 1990s.

4.2 Demand Options

The strategy calls for market research and development work to enable timely and efficient implementation of demand options (Consideration 3.6.1). Some demonstration programs are underway with more to follow.

Among them are programs to test acceptance of industrial high efficiency motors and processes such as mechanical vapour recompression. A joint program with the provincial government is testing increased use of monitoring equipment to encourage greater energy efficiency in industry. These research activities serve as the first steps towards implementation.

Additional research and development is needed on load shifting, particularly as it relates to rate structures. The strategy permits time differentiated rates as an incentive to shift load (Consideration 3.8.2). A joint agreement has been reached between municipal utilities, industrial consumer groups and Ontario Hydro on acceptable ways to introduce time-of-use rates. We plan to introduce bulk time-of-use rates in 1989 for industrial customers, subject to Ontario Energy Board review and approval by Hydro's Board of Directors.

A province-wide experiment with time-of-use rates for residential and commercial customers has been underway for several years, and will soon yield information on how Ontarians will accept and react to such rates. Plans are yet to be developed for introducing time-of-use rates for residential and commercial customers.

Estimates of load shifting potential are based on the assumption that time-of-use rates are in place.

The success of demand management will also depend on continuing information and consultation programs. Public information and education on the benefits of efficiency improvements should be stepped up (Consideration 3.7).

Consultation with municipal utilities will help accommodate local concerns. Utility cooperation is essential for successful demand management programs (Consideration 3.4).

Heavy reliance on demand options also requires changes to the load forecasting process. One change already in placed is to take explicit account of the expected contribution of demand management in the load forecast. Additional emphasis has been placed on end-use forecasting and forecasting the time varying pattern of loads.

4.3 Independent Generation

Attaining full economic potential from these programs will allow supply programs to be postponed.

Several independent generation projects are underway or in-service. For example, Hydro is buying power from a new wood-fuelled cogeneration plant at Chapleau. This project received provincial government funding. Also, a contract has been signed with Great Lakes Forest Products at Dryden for a cogeneration plant. This project will reduce the demand on Hydro's West System.

Negotiations are underway with another northwestern Ontario paper company. The goal of cogeneration demonstration projects is to find out how the risks, costs and benefits can be equitably shared.

Programs must recognize special local circumstances and may offer additional incentives where Ontario and renewable resources will be used.

Ontario Hydro will inform potential producers of the need for independent generation and will solicit proposals to fulfill that need. Contracts would be negotiated with suppliers whose proposals have potential to satisfactorily meet the need.

4.4 Hydraulic Generation

Work is underway on three projects:

- Approvals will be sought over the next two years for the Little Jackfish development, planned to be in-service by the mid 1990s to meet anticipated West System demands.

- The Mattagami extensions should be in-service during 1994 - 1996. The environmental assessment may be published in 1988 or early 1989.

- Concept work on Niagara River redevelopment is timed so that assessment and approval work can start in 1988.

Future studies are designed to identify additional sites that could be comparable in cost to other supply options and help meet loads in the most probable and upper forecast ranges.

4.5 Additional Base Load Energy Supply

As outlined in Section 2, additional base load supply could be required by 2001 under the most-likely scenario. With higher growth (Section 3), additional supply would be needed as early as 1996.

If lower growth should occur, no additional base load would be needed before 2010. The proposed work program recognizes this uncertainty.

Although plans should be driven by the most-likely scenario, planning should begin early enough so no option is ruled out simply by lack of time. Projects can be delayed if necessary (Consideration 5.2.1). Section 3 notes it is already too late to meet all needs in the upper growth case with new base load supply because of long lead times.

For this illustrative plan, early conceptual work on a nuclear and a coal station would be required so both could be available when a choice is made. Planning would include feasibility studies, specifications, costs estimates, detailed design and preparation of the environmental assessment. The environmental assessment could be submitted to the province in 1991 with public hearings likely in 1992. It should be noted that proceeding with this preliminary engineering and environmental approvals does not commit the construction of a generating station. It only provides the capability to construct the plant in the shortest possible time once the need is more clearly defined.

If nuclear is chosen, construction would have to begin around 1993, assuming eight years between commitment and first unit in-service. However, if coal is selected, construction would not need to start until 1995, with five to six years before first unit in-service.

By the time of an environmental assessment review for major new supply, we will have five years experience with demand management demonstrations and two to three years experience with practical demand options.

If demand management proves more successful than anticipated, construction can be postponed. However, it is imperative that all the planning elements are in place, in time.

Negotiations for major purchases from Hydro-Quebec and Manitoba Hydro should continue, based on a cost comparison with new nuclear generation, at present the lowest cost alternative.

Table 1

Strategy Implementation - Most Likely Load Growth

Committed Additions	MW	
Darlington (1988-1992)	3524	
Existing System - Maintenance & Improvements		
Lakeview - life extension of 10 or more years (by 1996)	2400	
Lennox return to service	2200	
FGD control retrofit * (1994-2002)	3000-8000	
Other Rehabilitations	As Necessary	
New Resources by 2000 **		
Efficiency Improvements	400-2250	
- more efficient motors		
- commercial lighting		
- heat pumps		
- mechanical vapour recompression		
Load Shifting	500-1000	
- time-of-use rates		
- thermal energy storage		
Independent Generation	300-1000	
Hydraulic		
. Little Jackfish (1995)	129	
. Mattagami Redevelopments (1994-1996)	398	
. Niagara Redevelopment (1998)	540	
. Other	0-200	
Total New Resources Required by 2000		
Dependable Capability:		2,600 MW
Approximate Generation Equivalent:		3,200 MW
Additional Resources by 2010 **		
Efficiency Improvements	200-750	
Load Shifting	300-500	
Independent Generation	200-440	
Hydraulic	600-1000	
Lakeview - Further Rehabilitation	0-2400	
Additional Base Load Energy Supply	1000-5000	
Total New Resources Required from 2000-2010		
Dependable Capability:		5,400 MW
Approximate Generation Equivalent:		6,700 MW

* Or equivalent. The emission control improvements do not add to capacity but allow existing fossil capacity to be more fully used.

** The MW values for new resources by 2000 and additional resources by 2010 should not be added to derive an estimated range of total planned resources. The reason for this is illustrated by example: if the upper range of efficiency improvements is achieved, it is likely that some of the hydraulic developments would be deferred.

Table 2

Strategy Implementation - Upper Load Growth Scenario *

Committed Additions	MW	
Darlington (1988-1992)	3524	
Existing System - Maintenance & Improvements		
Lakeview - 10-year life extension (by 1996)	2400	
Lennox return to service	2200	
FGD control retrofit (1994-1999) **	6000-8000	
Hearn & Keith Rehabilitations	1600	
Other Rehabilitations	As Necessary	
New Resources by 2000 ***		
Efficiency Improvements	600-2500	
- more efficient motors		
- commercial lighting		
- heat pumps		
- mechanical vapour recompression		
Load Shifting	500-1500	
- time-of-use rates		
- thermal energy storage		
Independent Generation	up to 1000	
Hydraulic		
. Little Jackfish (1994)	129	
. Mattagami Redevelopments (1994-1996)	398	
. Niagara Redevelopment (1998)	540	
. Other	600	
Additional Base Load Energy Supply	500-1000	
Total New Resources Required by 2000		
Dependable Capability:		9,300 MW
Approximate Generation Equivalent		11,500 MW
Additional Resources by 2010 ***		
Efficiency Improvements	400-1400	
Load Shifting	400-1000	
Independent Generation	200	
Hydraulic	600	
Lakeview - Further Rehabilitation	2400	
Additional Base Load Energy Supply	9,000-12,000	
Total New Resources Required from 2000-2010		
Dependable Capability:		12,700 MW
Approximate Generation Equivalent:		15,700 MW

Deficit/Purchase

The above options for new resources and additional resources are insufficient to meet the load between 1996 and 2001. The maximum deficit would be about 2000-4000 MW. This deficit cannot be met with the above options due to lead time constraints. The imbalance between demand & supply would result in a temporary decline in reliability, or could be mitigated by higher cost demand management options or by a major purchase.

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* Higher growth recognized in 1991

** Or equivalent. The emission control improvements do not add to capacity but allow existing fossil capacity to be more fully used.

*** The MW values for new resources by 2000 and additional resources by 2010 should not be added to derive an estimated range of total planned resources. The reason for this is illustrated by example: if the upper range of efficiency improvements is achieved, it is likely that some of the additional base load energy supply would be deferred.

Table 3

Strategy Implementation - Lower Load Growth Scenario *

Committed Additions	MW	
Darlington (1988-1992)	3524	
Existing System - Maintenance & Improvements		
Lakeview	mothball **	
FGD Control Retrofit	none	
Hearn, Keith & Lennox	remain mothballed **	
New Resources by 2000		
Efficiency Improvements	20-100 ***	
Load Shifting	500-900	
Independent Generation	0-150	
Hydraulic		
. Little Jackfish (1995)	129	
. Niagara Redevelopment (1998)	540	
Total New Resources Required by 2000		0
Additional Resources by 2010		
Efficiency Improvements	***	
Load Shifting	0	
Independent Generation	0-125	
Total New Resources Required from 2000-2010		0

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* Lower load growth recognized in 1991

** Subject to operability of the BES.

*** Not required for system reliability. Efficiency programs would likely continue, but the level of incentives that could be offered would be reduced and the MW impact would likely be negated by load building programs.

Table 4

Short-Term Work Program

	Type of Work	Time Period	To enable in service by:
Committed Additions			
Darlington NGS	- Construction	to 1992	1988-1992
Existing System			
Lakeview	- Life Extension Inspection	1986-1988	
	- Life Extension Work	1989-1993	
Lennox, Hearn, Keith	- Maintain in mothballs	ongoing	
FGD Scrubbers	- Concept work & EA	1986 -	As required -
	- Specification	1988 -	(earliest 1994)
New Resources			
Efficiency Improvements	- Research, Development & Market Demonstrations	ongoing	1990-onward
	- Actual Programs	ongoing	
Load Shifting	- Research, Development & Market Demonstrations	ongoing	1990-onward
	- Implement Time of Use rates	1989/90	
Independent Generation	- Demonstrations		1990-onward
	- Negotiations	1987-89	1990-onward
Hydraulic			
- Little Jackfish	- EA Process	1986-89	1994
- Mattagami	- EA Process	1986-89	1994-1996
- Niagara	- Concept Work	1987-88	
	- EA Process	1988-91	1998
Additional Base Load Supply			
- Coal and Nuclear	- Concept & EA	to 1992	As required (earliest 2001)
- Purchases	- Negotiations	ongoing	As required (earliest 1997)

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